CONSULTATION REPORT

Public consultation Task Force Princess Elisabeth Zone

This public consultation lasts from 20th November 2023 until the 22th of January 2024

Foreword

Princess Elisabeth Island is an unparalleled project in Belgium - a first-of-its-kind artificial energy island connecting offshore wind energy and serving as a landing point for interconnectors to other countries. This report goes in the details of the challenges triggered by such project and will appeal to different publics.

Its main audience is considering to develop offshore wind farms in the Princess Elisabeth Zone. The goal is to provide them all the necessary information for efficient and fair participation in the tenders organized and foreseen by the authorities end 2024. Many candidate developers were providing us with valuable insights in the Task Force Princess Elisabeth Zone and ad-hoc workshops, organized during the last two years. This report wraps up the work in a consistent package, making it available to a wide audience. The opportunity is provided to comment on the conclusions. This input will enable Elia to finalize the requirements that will apply to the offshore wind parks ahead of the first tender, planned in late 2024.

However, its relevance extends beyond developers to include other Transmission System Operators (TSOs), project developers, industry associations, regulators, and policymakers. It builds on the knowledge developed in the last years around offshore developments, through reports from ENTSO-E, European Commission and other projects, but it goes significantly deeper as it looks at the practicalities of an actual project, which triggers new questions. By all standards this is a technical report: no nice picture, but deep expert content. The expertise is at the cross-roads of different fields – some parts may appeal more than others depending on the individual background and interest. Concretely, it contains four main parts:

1) **Connection Requirements:** Relating mostly to infrastructure work, explaining the design of the artificial energy island and how wind farms will connect to it;
2) **Dynamic and Harmonic:** Addressing challenges related to managing large amount of power electronics, looking at the evolving nature of the system, and emphasizing the need for new collaborative approach in the detailed design of the assets;
3) **Market Design:** Focusing on the implications of hybrids interconnectors, and on the offshore bidding zone and its implications for wind parks, with special attention and new insights regarding advanced hybrid coupling and the issues raised with explicit coupling when considering hybrid assets with Great Britain;
4) **Balancing:** Examining the exceptional challenges of integrating 5.8 GW of offshore wind in the Belgian offshore North Sea and giving insights on the impact of the small Belgian system from a balancing perspective. Proposing measures for scenarios where the market cannot resolve the situation. Looking into the load-frequency structure of the future Belgian system with the development of an offshore bidding zone.

This foreword gives only a sneak preview of the topics. Each chapter starts with an executive summary which gives a more comprehensive view on the content. As you go through this report, we hope it offers new insights into uncharted territory. Your thoughts and feedback are valuable as we collectively work towards a sustainable energy future.

Table of Content

List of Acronym

AAP	Available Active Power
AC	Alternating Current
ACE	Area Control Error
ACER	Agency for the Cooperation of Energy Regulators
aFRR	Automatic Frequency Restoration Reserves
AHC	Advanced Hybrid Coupling
ATC	Available Transmission Capacity
AVR	Algemeen Veiligheids Reglement/General Safety Regulation
BE	Belgium
BdH	Boucle du Hainaut
BESS	Battery Energy Storage Systems
BOSIET	Basic Offshore Safety Induction and Emergency Training
BRP	Balance Responsible Parties
CACM	Capacity Allocation and Congestion Management
CA-EBS	Compressed Air Emergency Breathing System
CCR	Capacity Calculation Region
CF	Capacity Factor
CPS	Cable Protection System
CorRES	Correlations in Renewable Energy Sources
CREG	Commission for Electricity and Gas Regulation
CRM	Capacity Remuneration Mechanism
CTV	Crew Transfer Vessel
DC	Direct Current
DET n-1	Deterministic N-1 dimensioning incident
DK	Denmark
DP	Dynamic Positioning
DTU	Technical University of Denmark
EATFO	Earthing and Auxiliary Transformer
EDS	Electrical Distribution Subsystem
EEZ	Exclusive Economic Zone

EFB	Evolved Flow-Based
EMT	Electro Magnetic Transient
ENTSO-E	European Network of Transmission System Operators for Electricity
EON	Energization Operation Notification
ERCOP	Emergency Response Coordination Plan
ERP	Emergency Response Plan
FAT	Full Activation Time
FB	Flow-based
FCR	Frequency Containment Reserve
FDP	Federal Development Plan
FGC	Federal Grid Code
FON	Final Operational Notification
FPS	Federal Public Service Economy
FRCE	Frequency Restoration Control Error
FRP	Fiber Reinforced Panels
FRR	Frequency Restoration Reserves
FRT	Fault Ride Through
GB	Great Britain
GD	Grid Design
GIS	Gas Insulated Switchgear
GWO	Global Wind Organization
HM	Home Market
HUET	Helicopter Underwater Escape Training
HV	High Voltage
HVDC	High Voltage Direct Current
HVFRT	High Voltage Fault Ride Through
HWS	High Wind Speed
Hz	Hertz
IAC	Inter Array Cable
IBR	Inverter-Based Resource
IDPCR	Intra-Day Program Change Request
IEM	Internal Energy Market
ION	Interim Operational Notification

IP	Intellectual Property
IPCC	Intergovernmental Panel on Climate Change
Isc	Short-circuit current
JRC	Joint Research Centre
kV	kiloVolt
LFC	Load Frequency Control
LON	Limited Operation Notification
MARI	Manually Activated Reserves Initiative
MD	Ministerial Decree
mFRR	manual Frequency Restoration Reserve
MIC	Marine & Island Coordination
MIIF	Multi Infeed Interaction Factor
MOG	Modular Offshore Grid
MRCC	Marine Rescue Coordination Centre
MRLVC	Multi-Region Loose Volume Coupling
MVAr	Mega Volt Ampere Reactive
MW	Mega Watt
MWh	Mega Watt-hour
NDA	Non-Disclosure Agreement
NEMO	Nominated Electricity Market Operator
NI	Northern-Ireland
NPT	Neutral Point Transformer
NRA	National Regulatory Authority
O&M	Operations & Maintenance
OBZ	Offshore Bidding Zone
OEM	Original Equipment Manufacturer
OPA	Outage Planning
OWF	Offshore Wind Farm
PCC	Short-circuit power
PEI	Princess Elisabeth Island
PEZ	Princess Elisabeth Zone
PGM	Power Generating Modules
POC	Point Of Coupling

PPC	Powerk Park Controller
PPM	Power Park Module
PSCAD	Power Systems Computer Aided Design
PSS	Security and Health Plan
PTW	Permit To Work
RES	Renewable Energy Sources
RfG NC	Network Code Requirement for Generators
RGIE	Règlement Général des Installations Electriques
RMS	Root Mean Square
RRL	Ramp Rate Limitation
SA	Scheduling Agent
Scc	Short circuit apparent power
SD	Standard Deviations
SDAC	Singled Day Ahead Coupling
SHC	Standard Hybrid Coupling
SI	System Imbalance
SLD	Single Line Diagram
SMIB	Single Machine Infinite Bus
Snom	Nominal Apparent Power
SOGL	System Operation Guideline
SP	Shadow Price
SPGM	Synchronous Power-Generating Module
SPM	Storage Power Module
SSTD	Side-to-Side Tower Damper
T&I	Transport & Installation
TAG	Transmission Access Guarantee
TCA	Trade and Cooperation Agreement
TSO	Transmission System Operator
UK	United Kingdom
VHBE	Virtual Hub Belgium
VPA	Vessel Project Acceptance
VSP	Voltage Service Provider
3WT	Three-Winding-Transformer

1. Introduction

1.1. Context

Belgium has currently connected up to 2261 MW of offshore wind capacity distributed across 9 state concessions in the first zone of 238 km² in the Belgian Exclusive Economic Zone. The construction of the first offshore wind farms started in 2008 and ended in 2020 with the commissioning of the Northwester 2 offshore wind farm.

In 2021, the Belgian Government decided to further increase the offshore wind capacity by connecting 3.15 GW to 3.5 GW of additional offshore wind capacity by 2030[1]. A second zone of 285 km² in the Belgian Exclusive Economic Zone and called Princess Elisabeth Zone (PEZ) was identified to install this additional capacity and where the Council of Minister approved the development of offshore grid infrastructure that can transmit 3.5 GW. As answer to this new ambition to connect this additional offshore wind capacity to the Belgian coast, Elia will construct the Princess Elisabeth Island (PEI) in the Princess Elisabeth Zone. This worldwide first artificial energy island will play the role of electricity hub that will connect the new offshore wind farm installed in the PEZ and will also serve as a landing point for interconnectors with neighboring countries such as Great-Britain with Nautilus and Denmark with TritonLink.

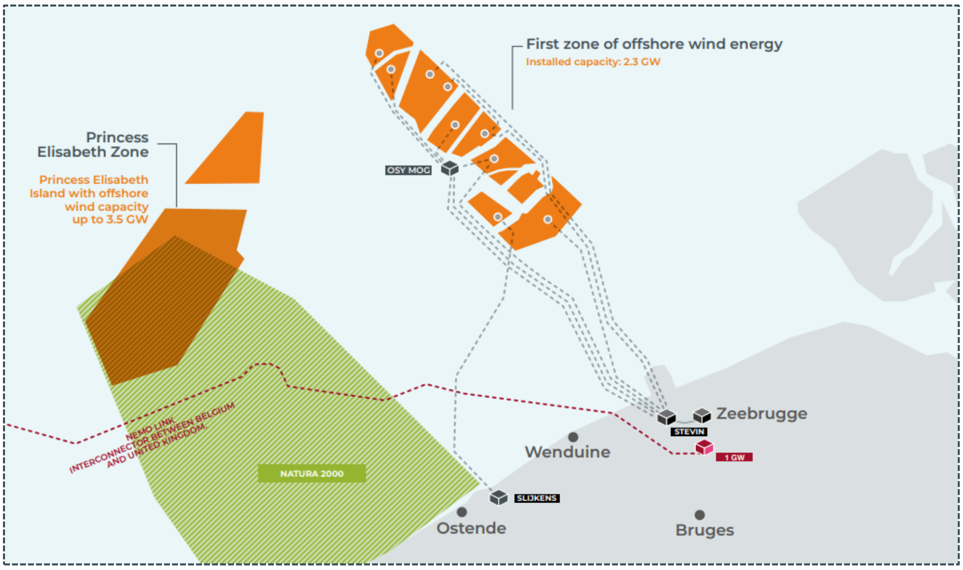


Figure 1 : Location of the different phases of offshore development in the Belgian North Sea

[1] *More info on website FPS Economy:* https://economie.fgov.be/en/themes/energy/belgian-offshore-wind-energy

Two tender phases are foreseen for the construction and the operation of the offshore wind in the Princess Elisabeth Zone[2]:

- **Phase 1 - Lot 1**: a first tender is scheduled for Q4 2024 for 700 MW offshore wind capacity that will be connected to an AC substation on the Princess Elisabeth Island and will be connected to shore with the condition that the Ventilus project, a new high voltage corridor connecting the internal high voltage backbone and the shore area, is ready;

- **Phase 2 - Lot 2 & 3:** a second tender for a first lot of 1225 to 1400 MW offshore wind capacity the Princess Elisabeth Island and a second lot of 1225 to 1400 MW. This capacity is foreseen to be connected to the Belgian coastal area with the condition that Boucle du Hainaut, a reinforcement of the internal Belgian high voltage backbone, is ready. The tender is foreseen to start Q4 2025.

This document is developed in the preparation and in the framework of the **different tenders** for the Princess Elisabeth Zone based on all relevant aspects related to the Princess Elisabeth Island project, as presented and discussed in the Task Force Princess Elisabeth Zone (PEZ) and ad-hoc workshops held in 2022 and 2023 by Elia.

1.2. Scope and planning of the public consultation

Elia organized a series of Task Force PEZ and ad-hoc workshops in 2022 and 2023 to engage with stakeholders regarding the Princess Elisabeth Energy Island. All materials, such as agenda, presentations, and minutes of the meetings are available on the Elia website in the Task Force PEZ webpage[3].

These stakeholder interactions were meant to actively engage with candidate developers and stakeholders to ensure transparency, gather input, and address any concerns related to the Princess Elisabeth Energy Island project. This collaborative approach can help in making informed decisions and ensuring the project's success.

In this framework, Elia is organizing this public consultation on the topics addressed in the Task Force PEZ and ad-workshop to consolidate the outcome of the exchanges.

[2] *More info on FPS Economy website: https://economie.fgov.be/en/themes/energy/belgian-offshore-wind-energy*

[3] *More info on Task Force PEZ webpage: https://www.elia.be/nl/users-group/task-force-princess-elisabeth-zone/meetings*

This public consultation is a voluntary initiative by Elia and aims at receiving any comment from market participants on the different topics presented in this document by taking account the instructions described in the Section 1.3.

The consultation period is set **from 20/11/2023 until 22/01/2024**, as publicly announced on the Elia website and discussed in the Task Force PEZ on October 19, 2023. This document covers the principal topics as addressed in Task Force PEZ and ad-hoc workshop summarized as following:

1. **Connection requirements:** summary of technical aspects presented during Task Force and ad-workshops;
2. **Dynamic & Harmonic:** clarifications of amendments in the technical specifications related to Dynamic & Harmonic phenomena that will be included for the offshore tender for the PEZ to be consider in the design of the offshore wind farm;
3. **Market design:** justification of the target market design including the role of an offshore bidding zone, the implications it has on the integration of offshore wind in wholesale markets, and an outlook on the process (how, when) to formalize the offshore bidding zone;
4. **Balancing design:** analysis of the planned offshore developments on real time system operation and balancing, the recommendation of mitigation measures to handle storm and ramping events, and the implications for the offshore bidding zone on balancing market design.

Additional details on the content of these different topics are provided in Figure 2 below.

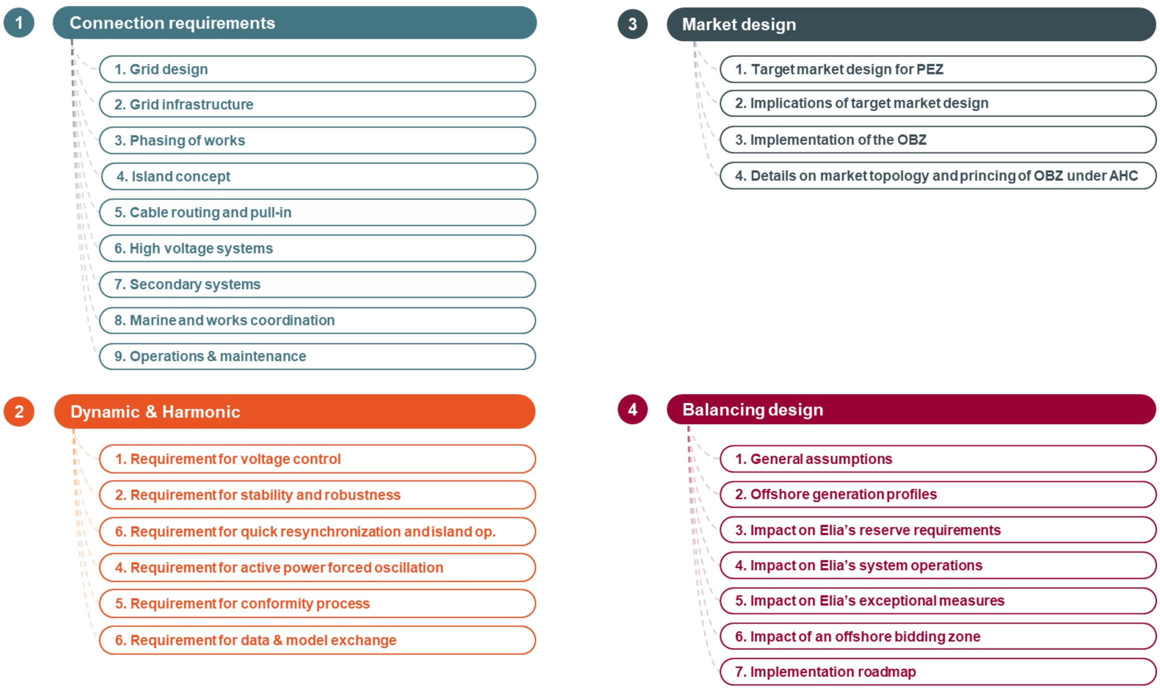


Figure 2 : Overview of topics addressed in the public consultation Task Force PEZ

The report aims to consolidate information from these discussions on the above topics to seek feedback from stakeholders. It's worth noting that the content of this consultation document has been discussed with market parties during the Task Force PEZ, and all relevant material is available on the Task Force PEZ webpage. The goal is to ensure a well-informed decision-making process by involving and considering the perspectives of the different stakeholders.

For the connection requirement aspects, the primary aim of this consultation is to provide stakeholders with an in-depth understanding of the project's key aspects, technical details, and operational considerations. Feedback and insights will contribute to the success of the Princess Elisabeth Island project.

Industry standards and the insights gained from the transmission network operator play a pivotal role in ensuring that the project will be efficient and reflect the best practices and benchmarks established by experts in the field. The active involvement and input from the stakeholders via this public consultation will align this project with these standards and practices, guaranteeing the delivery of a project that meets the expectations.

1.3. Instructions for reading this document

This document summarizes the topics communicated in the different Task Force PEZ/ad-hoc workshops organized by Elia in 2022-23 to be taken into account by the candidates developers for the tenders Princess Elisabeth Zone held late 2024 by the Belgian Authorities.

As foreseen in the Belgian Law (see Royal Decree in Info box below), Elia pro-actively shared the relevant information to the stakeholders through these different sessions organized in 2022-23 and formalizing these communications with the present public consultation with the 4 main chapters : Connection requirement, Dynamic & Harmonic, Market Design and Balancing Design. Each chapter starts with an executive summary which gives a more comprehensive view on the content.

Among other considerations, this report highlights the key technical requirements foreseen for these tenders PEZ, that will be submitted by Elia end Q3 to the Belgian authorities, and are ventilated mainly in the Section 2 for the connection requirements considerations, in Section 3 for the additional and clarifications of technical requirements triggered by Dynamic & Harmonics phenomena (power system stability) and finally the capabilities identified on the mitigation measures for balancing purposes (Section 5.9) to be taken into account in the design of the offshore wind farms.

Some aspects that have been discussed and concluded during the different Task Force meetings have led to decisions already made by Elia to ensure a timely delivery of the infrastructure. They are included in this report to give a comprehensive view and highlight the key considerations to be taken account in the design and business case evaluation, but they are not anymore open for adaptations. The aspects already decided are highlighted through the report and concerns mainly the connection requirements section.

The stakeholders are invited to submit comments and suggestions on the public consultation webpage. The consultation period runs from 20 November 2023 to 22 January 2024. After the consultation period, Elia will consider these comments and update the consultation report. In addition to the finalized report, Elia will publish the reactions of the market parties (including names) on the website, unless it is explicitly stated that the contribution is to be considered confidential.

Royal Decree (RD) of the Belgian law on technical regulations for the management of the electricity transmission network and access to it

Section 3 - Article 124 (FR)

Link: http://www.ejustice.just.fgov.be/eli/arete/2019/04/22/2019012009/justel

[…] Si le gestionnaire de réseau de transport constate un besoin pour le réseau de transport et justifie que ce besoin nécessite l'application d'une exigence technique pour un futur parc non-synchrone de générateurs en mer dont le ou les points de raccordement se trouve(nt) en mer, et compte tenu de l'impact que peut avoir cette exigence technique sur ledit parc non-synchrone de générateurs en mer, le gestionnaire de réseau de transport doit communiquer les besoins et la justification de l'application de l'exigence technique audit parc non-synchrone de générateurs en mer suffisamment en avance dans la procédure de raccordement. ***Cette communication peut également prendre la forme d'une consultation publique lorsque cette exigence technique est susceptible d'être appliquée à plusieurs parcs non-synchrones de générateurs en mer.****[…]*

Section 3 - Article 124 (NL)

Link: http://www.ejustice.just.fgov.be/cgi_loi/change_lg.pl?language=nl&la=N&cn=2019042202&table_name=wet

[…] Indien de transmissienetbeheerder een nood voor het net vaststelt en aantoont dat deze nood de toepassing van een technische vereiste voor een toekomstig offshore power park module noodzaakt waarvan het (de) aansluitingspunt(en) op zee ligt (liggen), en rekening houdend met de impact deze technische eis kan hebben op deze offshore power park modules, moet de transmissienetbeheerder deze noden en de motivering voor de toepassing van deze technische eis op deze offshore power park modules voldoende op voorhand in de aansluitingsprocedure communiceren. ***Deze communicatie kan ook de vorm aannemen van een publieke consultatie wanneer deze technische eis van toepassing kan zijn voor meerdere offshore power park modules.****[…]*

Section 3 - Article 124 (EN*)

****Translation based on FR/NL version***

[…] If the transmission system operator notes a need for the transmission system and justifies that this need requires the application of a technical requirement for a future non-synchronous fleet of offshore generators whose point(s) of connection is(are) at sea, and taking into account the impact that this technical requirement may have on said non-synchronous fleet of generators at sea, the transmission network manager must communicate the needs and the justification for the application of the technical requirement to said non-synchronous offshore generator park sufficiently in advance of the connection procedure. ***This communication can also take the form of a public consultation when this technical requirement is likely to be applied to several non-synchronous offshore generator parks.****[…]*

1.4. Legal and regulatory framework

The legal framework that applies for the Princess Elisabeth Zone is the continuity of what applies today for the existing MOG I wind farms slightly adapted with respect to an island configuration. The connection process itself is different, the connection is not allocated based on a single request from a known or new Grid User but via a tendering process. The public tendering process put forward by the authorities slightly changes the current process but aims at ensuring the best financial conditions for the end consumer.

In this context, Elia as Transmission System Operator (TSO) is legally mandated for defining the technical requirements and offshore specific guidelines. The purpose of this document is to detail the current intention of Elia regarding the requirements. Additionally, the reasoning behind those requirements is explained where necessary. This section will give an overview and a brief explanation of the contractual framework in order to clarify the role and purpose of each document.

Each selected wind farm developer will have to sign or comply with multiples contracts, guidelines and technical codes as summarized in the Figure 3.

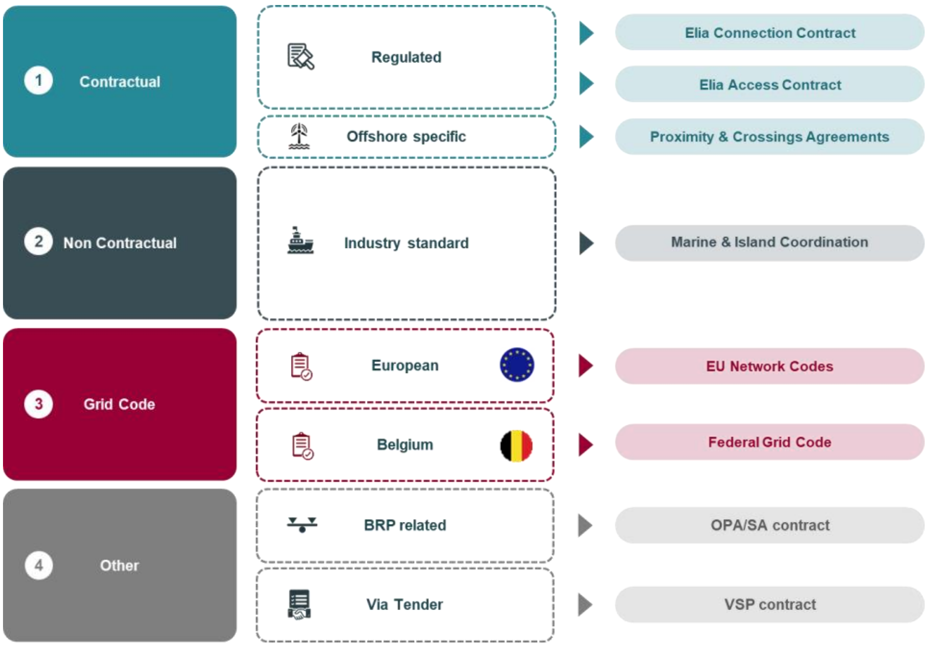


Figure 3 : Overview of the broader legal framework

As illustrated, distinctions are made between contractual & non-contractual documents next to the Grid Codes that apply for all power plants specifically based on their technical specifications (type, voltage & installed capacity) and finally a fourth group called 'Other'. This last group covers both the OPA/SA and VSP contract. The OPA/SA contract is required for production units as of a certain threshold and is the responsibility of the Balancing Responsible Party (BRP). The VSP contract falls under a specific tendering process wish will mostly likely evolve over time. Both contract will not be further detailed in this report but awareness has been raised in order to ensure completeness of this report. Below a timeline that illustrates the legal framework over time followed by a deep dive per category.

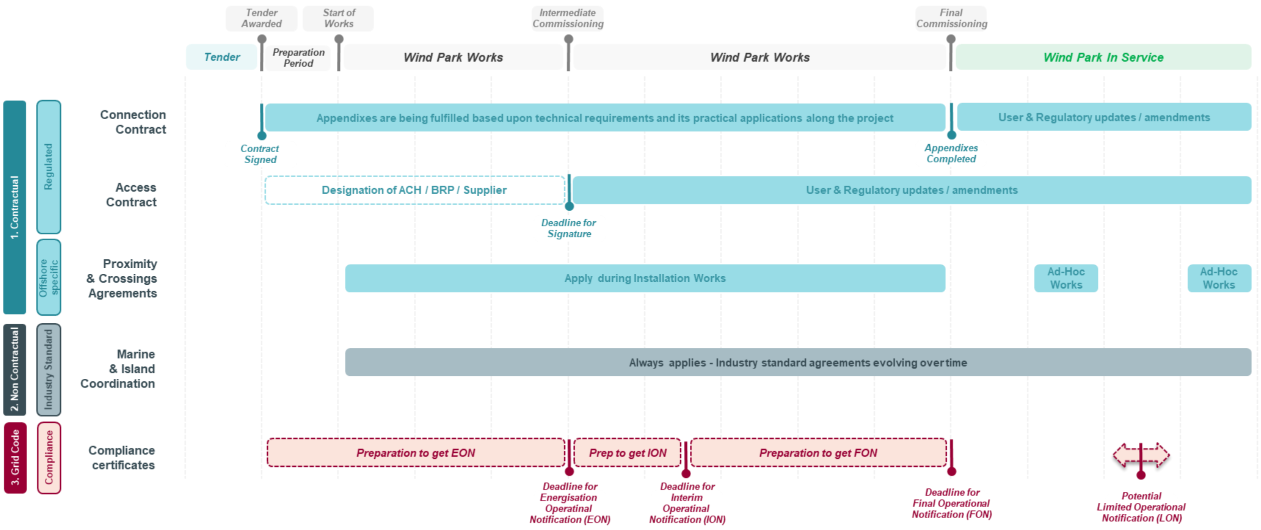


Figure 4 : The legal framework over time

1.4.1. Connection contract

A regular connection contract such as available on the Elia website will be used for the tender PEZ. The connection contract indicates the physical location (connection point) where the facility is connected to the Elia grid and the access point where energy is injected into or taken from the grid.

Connection contracts govern the contractual rights and obligations of both Elia and the Grid User in relation to, among other matters, rights of use, ownership, technical requirements, operation of connection facilities, etc. Note that the body of this contract is subject to amendments within the regulatory framework in place. Meaning that all existing or new Grid User are subject to similar contract changes. Each Grid User is strongly advised to take part to the public consultations organized by Elia to share its views and making sure to be aware of the upcoming evolutions of the contract. The CREG plays a major role in challenging proposition and making sure, they are in line with overall society interests. In this context, it should be mentioned that a consultation specifically on the connection contract is being organized and the outcome could slightly affect the structure of this contract. The timing of the connection contract consultation can be found on the Elia user group web page . It is warmly recommended to take part to this consultation in order to be aware of the latest amendments.

Focusing on the current version of the contract, next to the body, the contract is made of twelve appendices that will be filled based on the specifications of the offshore connection (from High Voltage Equipment up to grid requirements and access to installations). The appendix 12 is Offshore specific, stating the rights of access to offshore installation when the proximity agreement is not covering the scope under a specific installation works. As a general comment, all the requirements that will be found in the tender connection requirements, will be translated in the appendixes of the connection contract. As shown on the timeline above, the connection contract will be automatically assigned and de facto signed by the winning bidder. As of that moment, the appendix 8 of the signed connection contract will refer to the connection requirements communicated during the tender. Those requirements will then be contractual, with other words, the wind farm is expected to follow and apply those requirements in the context of the PEZ project. Once fully connected, all contractual appendixes will be fulfilled based on the connection requirements communicated during the tender and where needed some amendments based on what is actually installed (infrastructure, metering information, etc.) to match with the reality on field.

The connection contract also stipulates the different interfaces, which are further illustrated on the following figure and explained in the information box below. Typically, each wind farm will have multiple connection points.

Figure 5 illustrates a schematic view of the connection of a wind farm to the PEZ installations, where the wind farm will be connected physically to different position of the busbar 66kV, different connection points, but on a single access point grouping all the connection point. It's also worth noting that the metering will be done at the connection bay and the total injected and/or consumed energy will be the sum of all meters connected separately on each 66kV bay. Even if there would be a discontinuity between busbar via a longitudinal coupling leading or not to another physical location of the installation (i.e. another GIS room), the total measured value will group the metering of all meters.

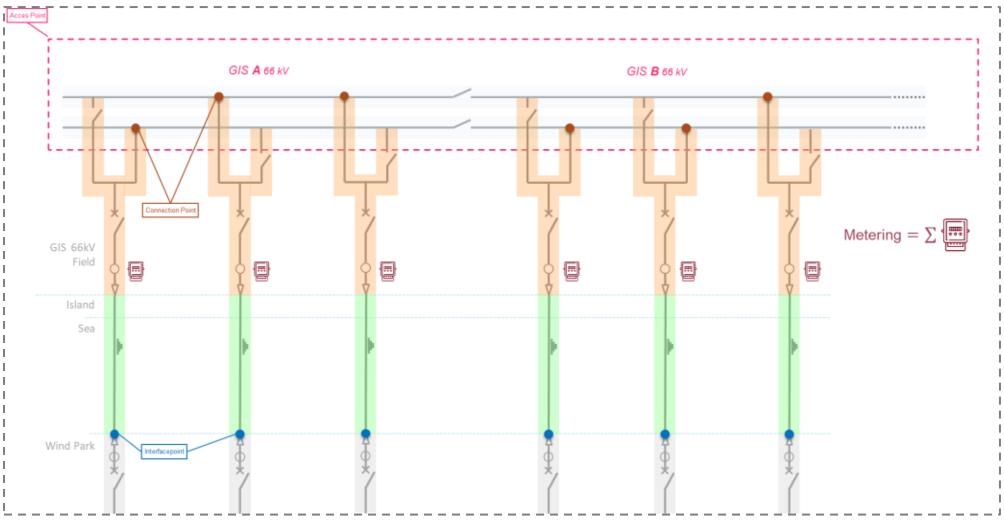


Figure 5 : Connection made of multiples connection points

Existing interface points for a connection field

The different interfaces for a connection can be summarized into 3 main categories:

Connection Point: The physical location and the voltage level of the point where the Connection is connected with the Elia Grid (in Figure 6, it is located between on the busbar 66kV right after the busbar disconnector) and that separates the facilities for which the disconnection has only consequences for the Grid user connected to that point;

Access Point: An Injection and/or Off-take Point; the Access Point is determined in Appendix 1 of the connection contract. As shown on the Figure 5 below, multiple connection points can Inject and/or Offtake at the same Access Point level.

Point of Interface: The physical location (in this case the cable head termination at the first wind turbine) and the voltage level (66kV) of the point where the grid user facilities (wind farm / first wind turbine) are connected to the Elia connection (by Elia connection it is understood, the Elia high voltage bay on the island and the wind farm cable making the link between the island and the first wind turbine. This cable belongs to the connection because Elia is in charge of protecting it). This point is located on the site of the grid user and in any case after the first Elia connection bay.

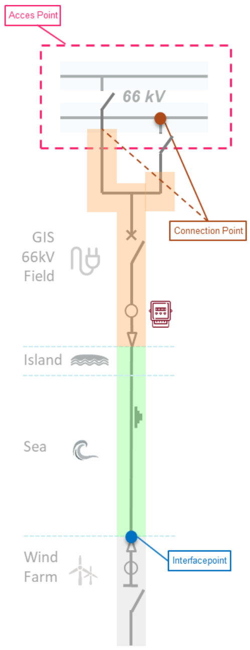


Figure 6 : Different interfaces for a single connection field

1.4.2. Access Contract

The signature of the access contract gives access to the grid. This contract governs the rights and obligations in force regarding use of the Elia grid. It applies to all access points to which the access holder has been granted access and which are recorded in the register of access points. The access contract will only come into force once a **bank guarantee** has been submitted by the access holder. The access contract between Elia and an access holder may be signed by either the grid user themselves or by a third party (e.g. supplier or BRP) appointed by the grid user to this end. This signatory is known as the access holder. The access contract governs the access rights and obligations of both Elia and the customer (or a third party appointed by the latter) concerning the fees for using the Elia grid (access tariffs). For the duration of the contract, the access holder is entitled, among others, under strict regulations, to add or remove access points to the contract, change supplier, change BRP, or appoint multiple BRP per access point. The access holder has also the access to all metering points of the access point.

1.4.3. Proximity Agreement

This Agreement governs the procedures, conditions and liability relating to the proximity activities. In order to allow the cable owner to exercise the proximity activities, Elia grants to the cable owner a non-exclusive right of access to the Elia Domain Concession and the Island, under the terms of the Proximity Agreement. Subject to Elia's prior written consent, the Cable Owner is prohibited from entering the Elia Domain Concession or exercising the Access Right in any manner other than as provided under this Agreement. This agreement is not regulated but refers to common practices and might evolve over time.

One single agreement file per cable owner will group all different agreements (crossings & proximity) that could arise between both the cable owner and Elia in the context of the Princess Elisabeth Zone and Princess Elisabeth Energy Island. Notice that the same agreement specification (cap, conditions, etc) will apply for all Proximity Agreements signed.

1.4.4. Marine & Island Coordination

As further detailed under Section 2.10, Elia is responsible of the Marine and Island Coordinator (MIC) for the Princess Elisabeth Zone. This Coordination is not contractual, but evolves over time by matching with industry standards. Different parties can be involved within the Marine and Island Coordination Construction Contractors (Island, AC/DC, Cables), Elia O&M (Operations and Maintenance) and Windfarm owners. As referred in the appendix 12 of the connection contract, when SIMOPS (Simultaneous Operations) are taking place, the MIC will apply to ensure proper coordination between parties involved.

1.4.5. Grid Codes

Both European and Federal Regulation apply for offshore grid connections. The EU Network codes are a set of rules drafted by ENTSO-E, with guidance from the Agency for the Cooperation of Energy Regulators (ACER), to facilitate the harmonization, integration and efficiency of the European electricity market.

On the other hand, the Federal Grid Code is the official code applying for connections at the federal level in Belgium. As further detailed under chapter 3. Dynamic & Harmonic, the conformity process will make sure those rules are followed. Along the project, based upon tests, models, studies and other evidences different certificates (Energization Operation Notification - EON, Intermediate Operation Notification - ION, Final Operation Notification - FON) will be delivered up to the final energization. Any later major change in infrastructure or technology along the lifetime of the wind farm could require to re-launch a conformity process, for which a specific certificate applies the Limited Operation Notification (LON).

2. Connection requirements

2.1. Executive Summary

The connection requirements describe the key technical aspects to facilitate the connection of offshore wind farm (OWF) to the electrical grid by taking into account the current industry best practices from offshore wind manufacturers as well as Transmission System Operator (TSO) perspective to ensure a safe, efficient and reliable operation.

This chapter summarizes the key aspects to be considered in the design of OWF in the Princess Elisabeth Zone (PEZ) that will be connected to the Princess Elisabeth Island (PEI): the grid design, grid infrastructure, phasing of the work on the island, the island concept, the cable routing and pull-in on the island, the high voltage and secondary systems, and finally all aspects related to marine/works coordination and operations & maintenance.

As Elia needed to progress the project to ensure a timely delivery of the infrastructure, some of these key aspects such as the grid design, the grid connection and island concept are already fixed and cannot be adapted but are shared in the framework of this public consultation to provide the necessary information and transparency to market players for the preparation of the Princess Elisabeth Zone tenders.

The Princess Elisabeth Island is the answer to the Belgian ambition to connect between 3,15 and 3.5 GW of additional offshore wind farms in the Belgian part of the North Sea, in a new zone called ‘Princess Elisabeth Zone’. This energy island will combine alternative current (AC) and High Voltage Direct Current (HVDC) technologies to tackle both the need to integrate these up to 3.5 GW of offshore wind and the need to access RES produced somewhere else in the North Sea.

The energy island is constructed out of concrete caissons in which J-tubes will be foreseen that will allow the pull-in of inter-array cables. On top of the energy island 4 AC substations will be constructed, which contain the 66kV bays to which the OWF will connect. In total 40 bays will be available for 3.5 GW of wind power, as well as 5 spare bays to guarantee flexibility in windfarm design.

To facilitate cable routing on the energy island concrete cable culverts will be installed. Around the energy island the offshore cable routing has been divided into dedicated cable corridors per windfarm. These cable corridors are designed to limit offshore crossings and maximize the available space per windfarm. Inside the AC substations Elia will provide an OWF room to allow installation of interface- and wind farm cubicles. The protections per inter-array cable will be provided by Elia, which can be used by the OWF and in such a case the settings need to be aligned between parties.

2.2. Introduction

The connection requirements for offshore wind farms ensure the successful integration of wind energy into the electrical grid while maintaining grid stability and grid reliability. These requirements include technical, regulatory and safety considerations, as well as insights on grid design, infrastructure, and operations. The following chapters cover different aspects related to the connection requirement and are summarized in Figure 7.

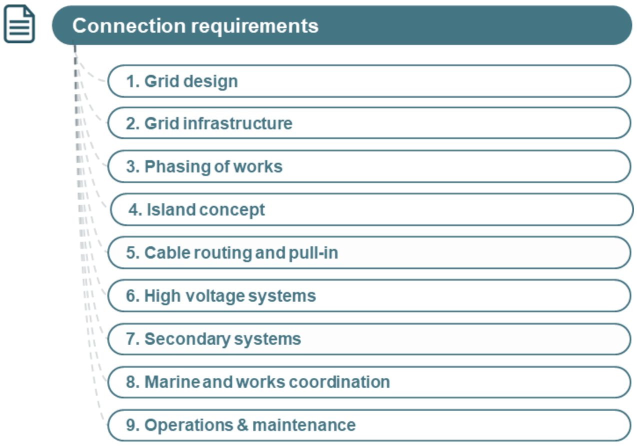


Figure *7 : Overview connection requirement topics*

The section on grid design focuses on the configuration of the electrical grid to optimize the energy transmission from the offshore wind farm to the onshore grid. The grid infrastructure section covers the equipment on the Island necessary for a reliable transmission of energy and includes high voltage systems, such as transformers, switch gear and cable systems, described in Section 2.8, such as control and monitoring systems, low voltage protections and communication networks are described in Section 2.9.

The high-level schedule and phasing of works outline the systematic approach to project execution, from tender to design, construction, installation and commissioning. Section 2.6 covers the relevant information about the island layout and the infrastructure installed on the island.

The concept and the requirements of marine and works coordination are described in Section 2.10 "Marine and works coordination". The goal of Marine and Island Coordination is to minimize the probability of an incident during the construction, installation, operations and maintenance. To meet this goal and to optimize the construction time, the Marine and Island Coordination system will oversee marine operations and island activities.

2.3. Grid design of the Princess Elisabeth Island

The grid design for the Princess Elisabeth Island has been developed at the light of Belgium's ambition to integrate additional Offshore Wind Farms (OWFs) in a new zone, called the "Princess Elisabeth Zone". The Princess Elisabeth Island conceptual layout is shown in Figure 8 and is elaborated on in Section 2.6.

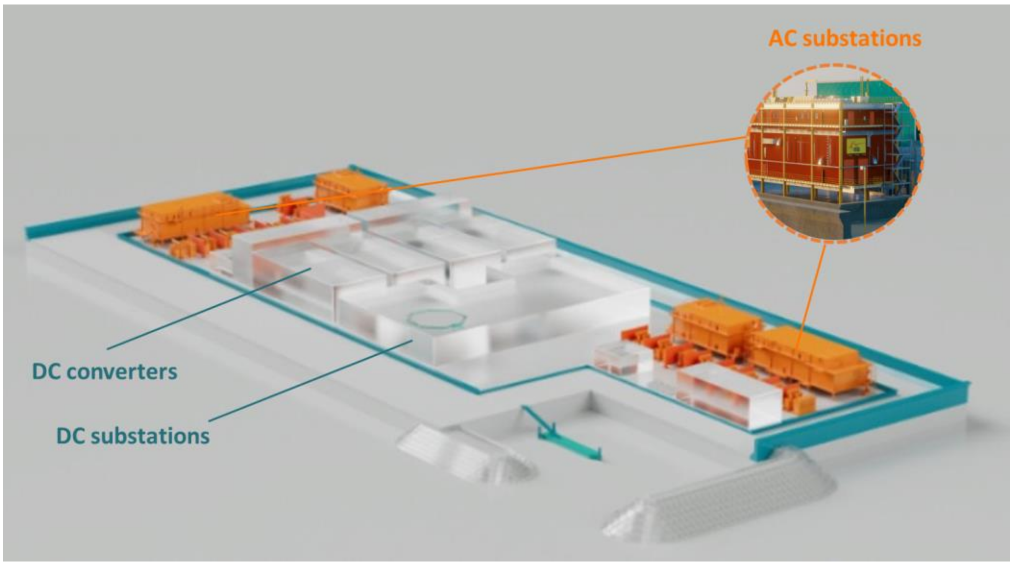


Figure 8 : Princess Elisabeth Island layout

The total capacity of these additional OWFs ranges from 3.15 GW up to 3.5 GW. A variant analysis has been performed to select the optimal solution for the integration of these OWFs. This variant analysis has been performed based on various criteria among which: the investment costs, the maintenance costs, the risk in terms of timing, the availability and reliability of the infrastructure, the technical complexity, the environmental impacts and the future-proofness.

Based on this analysis, the island solution combining both Alternating Current (AC) and Direct Current (DC) technology has been selected. In this solution, as depicted on Figure 9, the island is connected to the onshore network via 6 AC export cables and 1 HVDC system for a total capacity of 3,5 GW. This solution also offers opportunities for further expansions consisting of, among others, HVDC interconnectors to neighboring countries or hubs. It is also important to remind that the Princess Elisabeth Island relies on onshore reinforcements to be able to bring this significant inflow of energy up to where this energy is used. In particular, the Princess Elisabeth Island relies on the projects Ventilus and Boucle du Hainaut. Ventilus unlocks the injection of power from the first concession (700 MW) whereas Boucle du Hainaut is absolutely required to unlock the injection of power from the two remaining concessions (2 x 1400 MW).

In terms of access to the onshore network, the first concession will benefit from a flexible access on Ventilus, pending the finalization of Boucle du Hainaut, as described in Section 2.3.1. As soon as the project Boucle du Hainaut is finalized, a permanent access will be granted to the Princess Elisabeth Island, with a total capacity of 3500 MW.

On the 7th September 2023, this grid design has been approved in a Ministerial Decree (MD). A public version of the document describing and justifying the Grid Design for the extension of the Modular Offshore Grid is available on Elia's website[4].

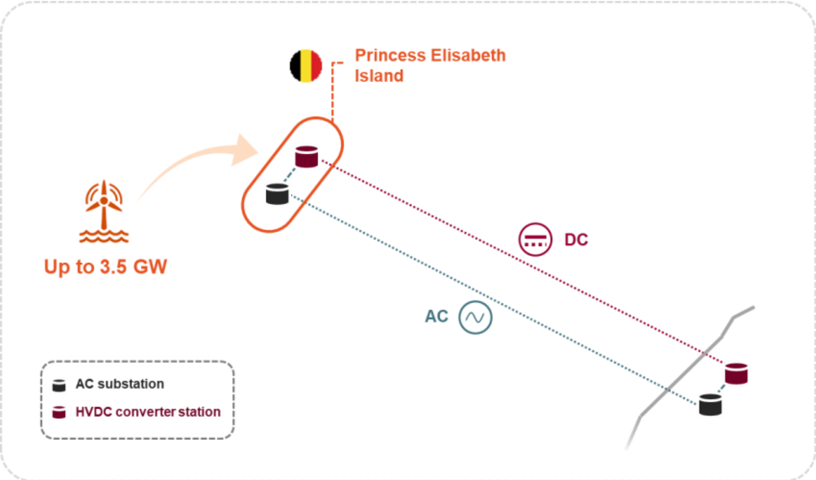


Figure 9 : Grid design for the Princess Elisabeth Island, as approved by Ministerial Decree on 07/09/2023

An important evolution with regards to the first step of the Modular Offshore Grid (MOG1) is that Elia is now also responsible for the transformation of the voltage from the one applied by the offshore wind turbines (66kV) to the one used to export the energy to the onshore network (220kV for the AC cables and +/- 525 kV for the HVDC cable system). This is the origin of many of the technical requirements listed in the present document.

[4] *More info on Elia website: https://www.elia.be/-/media/project/elia/elia-site/infra-and-projects/projects/energy-island/2023/20230823_proposition-grid-design-mog2.pdf*

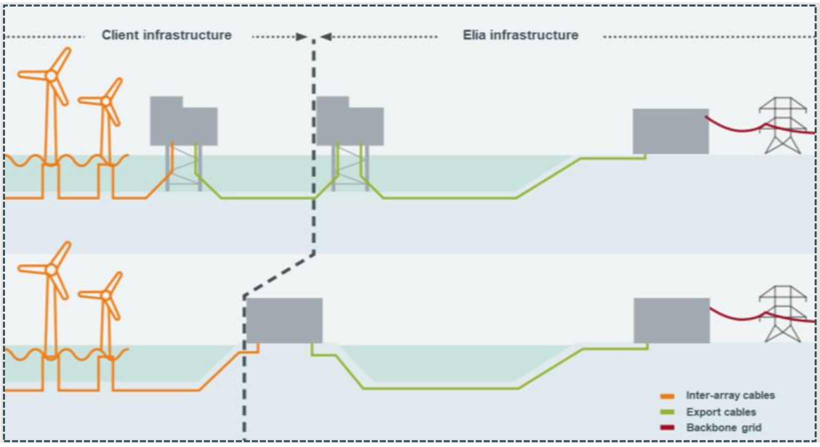


Figure 10 : Evolution of the responsibility conferred on Elia between the first offshore phase (top) and the second offshore phase (bottom)

In addition to the need to integrate vast amount of offshore wind in the PEZ, the Belgian Minister of Energy also requested Elia to foresee the offshore infrastructure such that they could participate to the realization of a network of offshore hubs in the North Sea. In other words, the infrastructure of the PEI has to tackle 2 needs: 1. Integration of Belgian offshore RES (Renewable Energy Sources) and 2. Access to RES produced somewhere else in the North Sea. This is indeed key for a country like Belgium with high ambitions in terms of electrification and, at the same time, limited domestic offshore RES potential.

This request matches quite well the observations made by Elia in the framework of its Federal Development Plan. The development of hybrid systems combining RES integration and interconnection functions may, in well selected locations, contribute to a more efficient use of scarce resources (€, environment, workforce, etc.). Of course, this must be checked case by case, which has been done for Nautilus, the project of (hybrid) interconnection between Belgium and the United-Kingdom. Indeed, the cost-benefit analysis has been performed in the framework of the Federal Development Plan and shows significant benefits for a reduced investment. This also translates in a faster delivery of the project, allowing Belgian and European society to quickly enjoy the significant benefits Nautilus brings. Figure 11 shows the high-level structure of the Princess Elisabeth Island after the realization of Nautilus, expected in 2030.

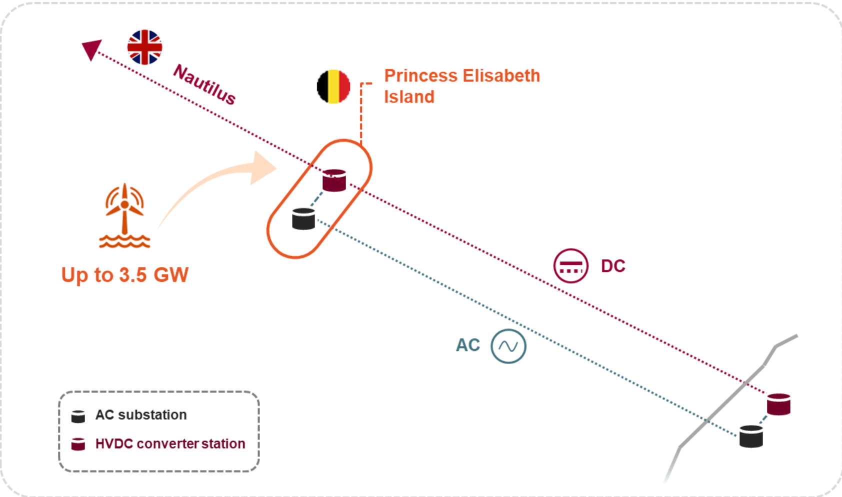


Figure 11 : High-level structure of the Princess Elisabeth Island following the realization of Nautilus

Nautilus will be realized with HVDC technology, and the goal is to connect it to the HVDC part of the Princess Elisabeth Island, via a HVDC substation. The ambition is to operate the Princess Elisabeth Island in "single node" (see Figure 12), meaning that the AC part of the island would be coupled to the DC part of the island. Doing so, the import capacity to Belgium would be increased in period of low wind, which comes along with extra benefits for the Belgian and European society. This ambition comes however with significant challenges related to the dynamic behavior of the power electronics connected in that area (wind turbines, HVDC converters, etc.). At this stage, the reference thus remains an operation in "split nodes" (see Figure 13), namely the AC part of the island decoupled from the DC part of the island. This will remain the reference as long as the dynamic risks are not properly mitigated.

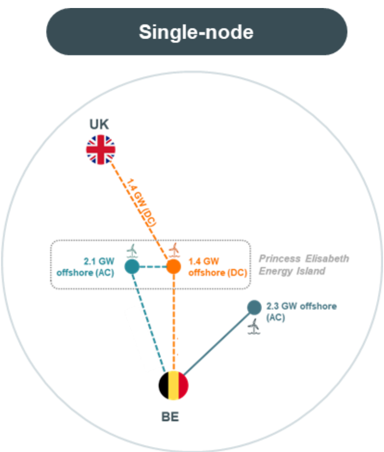


Figure 12 : Single node operation for Princess Elisabeth Island

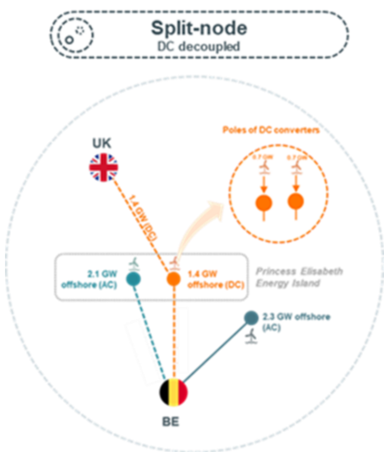


Figure 13 : Split node operation for Princess Elisabeth Island

On top of Nautilus, the hybrid interconnector TritonLink between Belgium and Denmark, will also be connected to the Princess Elisabeth Island. In a first stage however, the HVDC cable system will only pass via the Princess Elisabeth Island before going to its connection point located further inland in Belgium. As such, at this stage, TritonLink will not be electrically connected to the rest of the Princess Elisabeth Island. This stop of TritonLink on the island anticipates the realization of a major energy hub off the Belgian coast. This Offshore Energy Hub will consist in the realization of a common electrical node between the four following HVDC legs:

1) The HVDC system connecting the Princess Elisabeth Island (PEI) to the Belgian coast;
2) The HVDC system connecting the PEI to Great Britain (Nautilus);
3) The HVDC system connecting the PEI to Belgium, further inland (part of TritonLink);
4) The HVDC system connecting the PEI to the offshore hub located in Denmark (part of TritonLink).

The finalization of TritonLink is expected in 2031-2032 whereas the realization of the Offshore Energy Hub is expected later, between 2035 and 2040. For the realization of such a common node on HVDC technology is a DC circuit breaker required, or an equivalent technology, which is not yet mature at the time of writing. This technology is however critical in order to ensure a good selectivity in case of failure at any point of the interconnected HVDC system. Without this technology, any failure would affect the four legs listed here-above and jeopardize network stability in Europe.

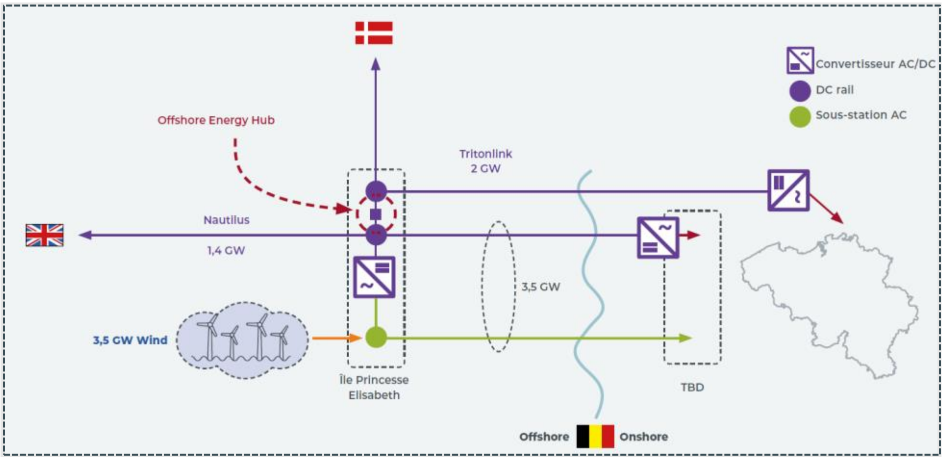


Figure 14 : High-level structure of the Princess Elisabeth Island following the realization of TritonLink and, in a later stage, the Offshore Energy Hub

2.3.1. 700 MW flexible connection access

To unlock the full hosting capacity in the Belgian costal area, both Ventilus and Boucle du Hainaut projects are required as highlighted in the Federal Development Plan 2024-34 of Elia[5]. Ventilus (2028-30) is to be commissioned before Boucle du Hainaut (2030). Without Boucle du Hainaut, already existing congestions on Horta-Mercator axis remain present in the system. These congestions are aggravated when supplementary generation is connected (e.g. offshore wind connection).

In order to support Belgium's ambition to accelerate the deployment of offshore wind energy in the Princess Elisabeth Zone, a maximum of 700 MW of offshore wind capacity (= phase I) can already be connected to the electricity system after the realization of Ventilus. However, production of this offshore wind farm needs to be limited in case of congestion on Horta-Mercator.

Given the fact that congestions can already occur in normal operation, this entails **preventive curtailment of possibly up to 700 MW. Such limitation of the offshore wind production is required for as long as Boucle Du Hainaut is not realized yet.**

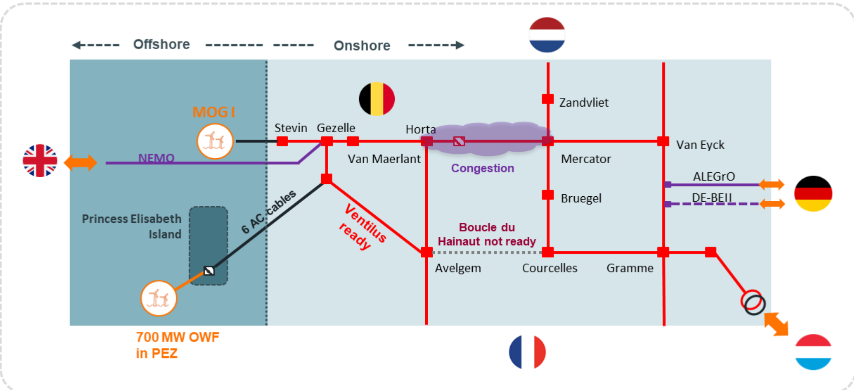


Figure 15 : Connection of 700 MW offshore wind capacity with Ventilus and without Boucle du Hainaut

Just like for any other client facing a similar situation (i.e., temporary congestions on the network pending the realization of a grid reinforcement project), a "Flex file" will be drafted and sent to the CREG for approval, ahead of the launch of the 1st OWF tender. This file will specify which congestions may lead to a limitation of the injection as well as the frequency and extent of these limitations.

[5] *More information available on the Elia website: https://www.elia.be/en/infrastructure-and-projects/investment-plan/federal-development-plan-2024-2034*

2.4. Grid Infrastructure

The grid infrastructure foreseen for the connection of the PEZ offshore wind farms to the Princess Elisabeth Island is described in the Section 2.4.1 with a simplified representation of the electrical system ("Single Line Diagram") and the power constraints behind this infrastructure.

2.4.1. Single Line Diagram

The Single Line Diagram (SLD) is built by taking into account the 3 concessions identified by the Belgian Government in the Princess Elisabeth Zone (PEZ):

1) Concession 1 (Lot 1): 700MW of offshore wind capacity;
2) Concession 2 (Lot 2): 1225 -1400MW of offshore wind capacity;
3) Concession 3 (Lot 3): 1225 – 1400MW of offshore wind capacity;

The inter-array voltage level for the offshore wind farms in the Princess Elisabeth Zone (PEZ) has been defined as 66 kV. This choice was based on the call for feedback organized by the Belgian Government on October 3, 2022. In total, 12 responses were received and confirmed earlier analyses performed by Elia: there are insufficient strong signals from the market (developers and supply chain) to justify introducing additional timing, cost and technological risks by imposing a 132 kV connection voltage for the Princess Elisabeth Zone. Due to these risks and the uncertainty (expressed by the market in the context of the Belgian Government consultation) regarding a timely technological readiness for this voltage level, **it was decided to fix the inter-array voltage of the Princess Elisabeth Zone at 66 kV**.

For the offshore (PEI) – onshore (Belgian coast) connection, 6 AC 220 kV cables and a DC connection with 2 DC cable connection s has been designed as illustrated in Figure 16.

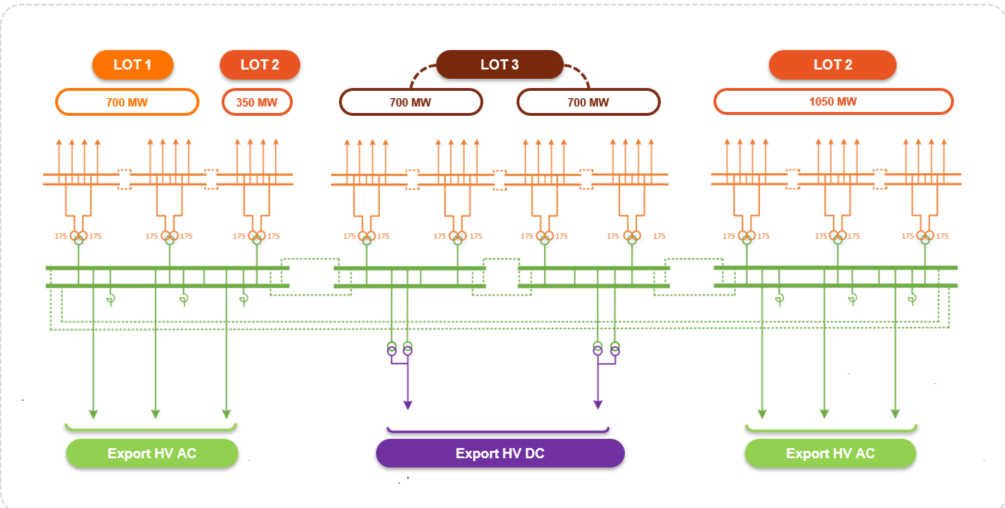


Figure 16 : Single Line Diagram of the Princess Elisabeth Island

The electrical system of PEI is characterized by 2 main types of blocks:

1) **Block of 220 kV:**
   i. **Layout 1 with 1050 MW** as shown in Figure 17;
   ii. **Layout 2 with 700 MW** as shown in Figure 18.
2) **Block of 66 kV:**
   i. **Layout 3 with 350 MW** representing a 66kV block as shown in Figure 19.

Where in the different layouts:

- The black bullets represent a closed connection in normal operating mode;
- The white bullets represent an open connection in normal operating mode.

► Layout 1 with 1050MW

The following assets are considered in this layout 1:

- 3x 220 kV AC export cables;
- 3x transformers 66/66/220kV;
- 3x shunt transformers 90MVAr;
- 4x link cable bays towards the adjacent 220kV 700MW and 220kV 1050MW block.

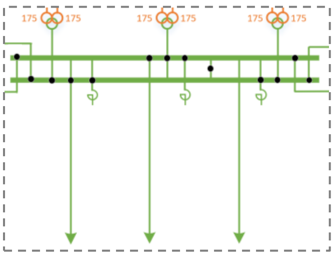


Figure 17 : 1050MW layout

► Layout 2 with 700MW

The following assets are considered:

- 2x 220 kV AC cable bays to connect the HVDC step-up transformers;
- 2x transformers 66/66/220kV;
- 4x link cable bays towards the adjacent 220kV 700MW and 220kV 1050MW block.

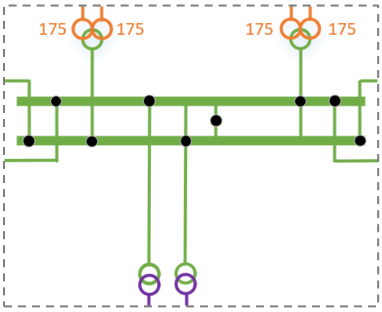


Figure 18 : 700 MW layout

Each 220kV block is designed with a double busbar system where the busbar coupling will be closed in normal operation.

► Layout 3: 350 MW - 66kV block

As shown in Figure 19, each 66kV block with 4 cable bays will connect 350MW of offshore wind power. Each block is operated independently from each other on the 66kV side. Each 66kV block is designed with a double busbar system, where the busbar coupling will be closed in normal operation. The offshore wind farm inter-array cables will be equally divided over the two busbars. One offshore wind farm will be connected to one 66kV block.

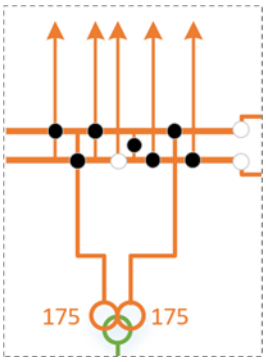


Figure 19 : 66kV block

The 66kV blocks are designed into:

- 4x cable bays (or OWF inter array cables) that can connect up to 350 MW
- 2x transformer bays 66/220kV connected to a power transformer of 400MVA with one primary 220kV winding and two secondary 66kV windings;
- 1x spare cable bay;
- 1x busbar coupling;
- 2x link cable bays towards the adjacent 66kV blocks.

Each 66kV block will have 1 spare bay (shown in Figure 19). A total of 10 spare bays will be installed on the Princess Elisabeth Island, of which 1 spare bay per 700MW connection will be available for the OWF:

1) Lot 1: 1 spare bay
2) Lot 2: 2 spare bays
3) Lot 3: 2 spare bays

The other spare bays will be dedicated for potential future connections (managed by Elia). Each 66kV bay (excl. the transformer bay 66/220kV) will have 1 cable end unit. Earthing and auxiliary transformer will be connected on the secondary side of the power transformer 400MVA.

The connection of the two ends of inter array cables as shown in illustrative Figure 20 will remain feasible for power supply for auxiliary services. However, Elia emphasis that in this configuration connecting two inter array cables on the busbar 66kV is strictly prohibited.

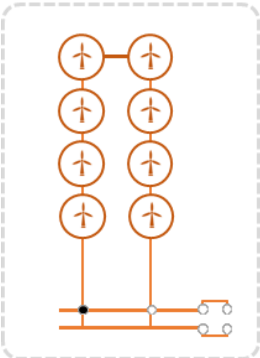


Figure 20 : The connection of two ends of inter-array cables (illustrative)

Elia has investigated the option of adding a circuit breaker on the first wind turbine and detects clear opportunities to achieve operational independence between the OWF and Elia during the operational phase. After receiving 6 constructive responses with a clear pushback on installing a circuit breaker and/or voltage transformers in the first turbine, Elia concludes that an extra circuit breaker is an interesting idea, but which brings extra complexity and costs to the OWF. **Therefore, it was decided that the circuit breaker will not be required in the first wind turbine and has not been considered in the further design.**

Correspondingly, Elia will require all switch (disconnector and earthing) positions from the OWF. The preliminary list of signal exchange has been added in Section 2.9.2 “Signal exchange”. Elia will provide the switching procedures during the detailed design phase.

2.4.2. Power constraints

In order to provide flexibility for the layout of the offshore wind farms, the following degrees of freedom are provided in terms of connection to the Princess Elisabeth Island:

1) As mentioned in the previous section, 1 spare bay per block of 700 MW is available to the OWF. In total, this represents 9x 66 kV bays per 700 MW;
2) No maximum injection or maximum installed capacity is imposed per 66 kV string;
3) The injection per block of 350 MW (i.e. per power transformer 66/66/220kV) cannot exceed 380 MW / 400 MVA;
4) The injection for each of the 3 concessions is strictly limited to their respective capacities, as identified by the Belgian government (i.e. 700 MW, 1400 MW and 1400 MW). It is up to the respective Offshore Wind Farms to make sure these limits are continuously respected;
5) The installed capacity may exceed the maximum level of power injection (i.e. overplanting) by maximum 5%, defined at the level of the tender (i.e. 735MW, 1470MW and 1470MW).

Note: *if some flexibility is provided in terms of repartition of power between the different transformers of a same concession, it is recommended to strive for an as good balance as possible in order to allow an optimal N-1 management. Indeed, in case of loss of a transformer, the offshore wind capacity connected to this transformer will be more efficiently rerouted to the other transformers if such a balance is achieved.*

2.5. Phasing of works

2.5.1. High-level schedule

The high-level timing foreseen for the Princess Elisabeth Island, the offshore wind farm and onshore grid reinforcement are defined in the Figure 21. The high-level planning has been also published on the FPS Economy website: https://economie.fgov.be/en/themes/energy/belgian-offshore-wind-energy

At the time of starting this consultation, the construction phase started for the Princess Elisabeth Island. The related assets (AC and DC substations, AC and DC cables) are currently in the tendering phase. Subsequently, Elia will proceed with detailed design, construction and installation. This information is summarized in Figure 21.

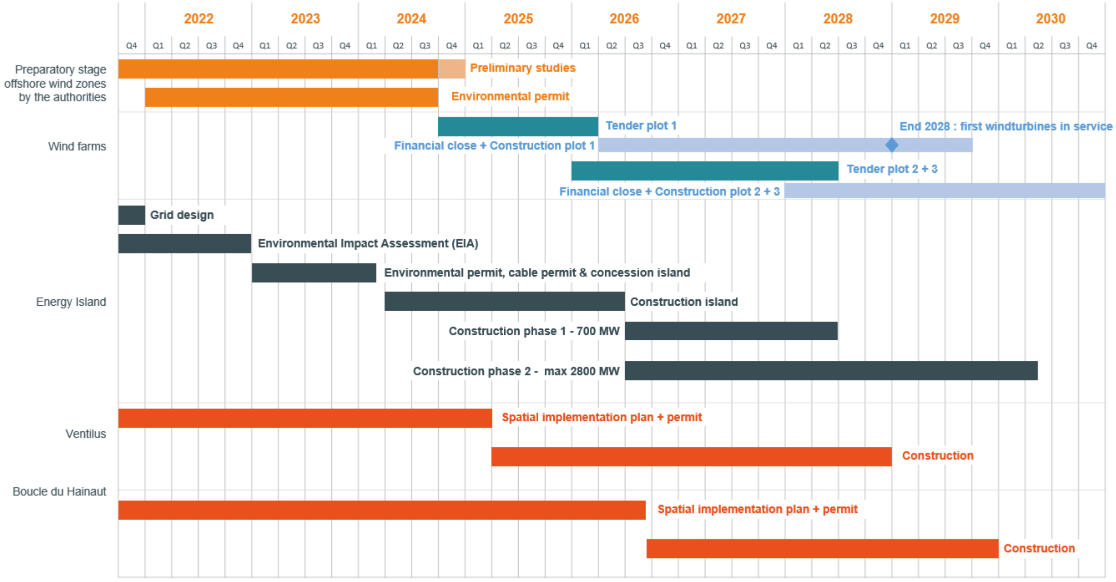


Figure 21 : High level timing for the Princess Elisabeth Island

2.5.2. Phasing of works on the island

Figure 22 gives an overview of the different phases of the offshore works foreseen in 3 steps:

1) **Phase 1** will include the installation and commissioning of one facility module and 1 AC substation 1050MW. With the commissioning of phase 1, the island will be ready to connect the first concession;
2) **Phase 2** will include the installation and commissioning of one AC substation module 1050MW. With the commissioning of phase 2, the island will be ready to connect the second concession;
3) **Phase 3** will include the installation and commissioning of two AC substation modules 700MW and the installation and commissioning of the onshore and offshore DC convertor. With the commissioning of phase 3, the island will be ready to connect the third concession.

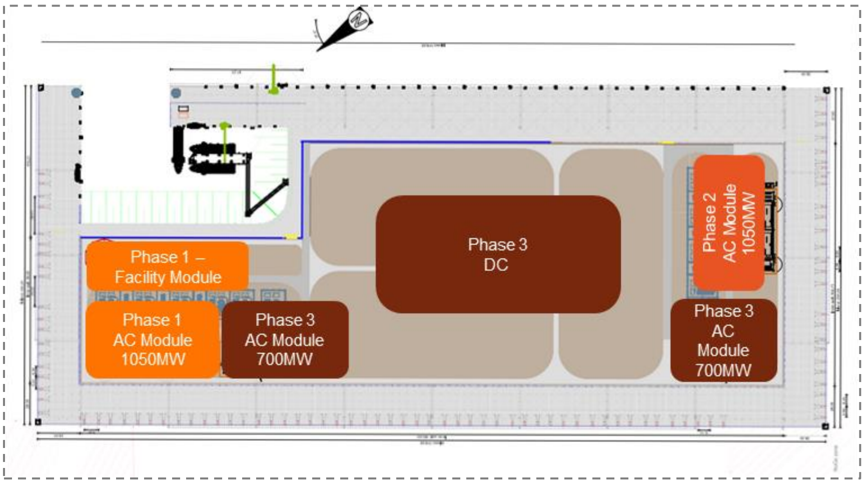


Figure 22 : Phasing of works foreseen on the Princess Elisabeth Island

2.6. Island concept

The electrical infrastructure will be installed on an island, located inside the Princess Elisabeth Zone. This Princess Elisabeth Island is divided in four main areas, visualized in Figure 23:

1) The land area at the center of the energy island, that will house the grid infrastructure;
2) The drainage buffer zone, which surrounds the land area (at north, south and west side), and mainly serves to collect overtopping (wave) water but also to route the cables;
3) The quay side on the east;
4) A CTV (crew transfer vessel) harbor.

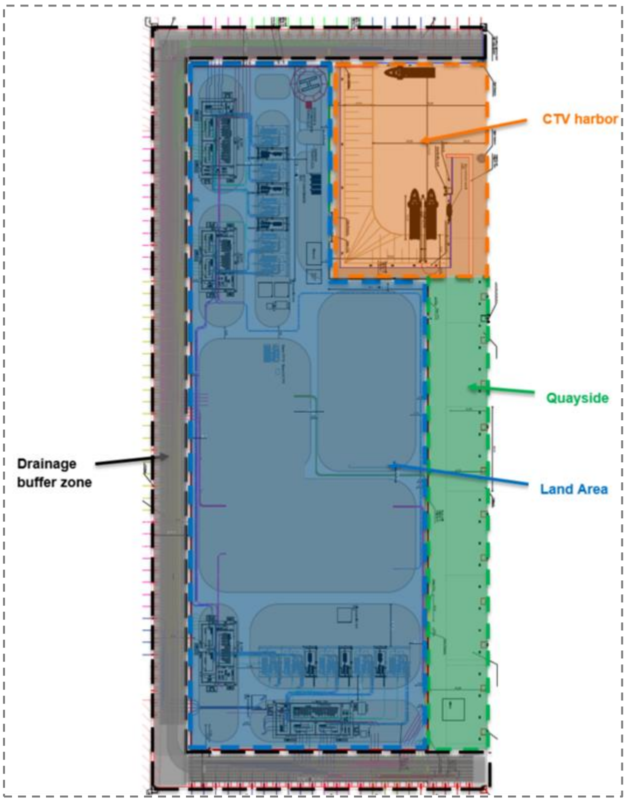


Figure 23 : Island layout

The exploitation, operation and maintenance of the island will be the responsibility of Elia. No accommodation for third parties is foreseen in the design. An emergency shelter has been included in the island design. CTV and Walk to Work transfers will be possible under supervision of Elia.

2.6.1. Land area

The land area measures approximately 6 hectares and will consist of several buildings for the DC converter and DC interconnectors, 4 AC substations as well as some small warehousing facilities. The windfarms will be connected to the AC substations, which consist out of 1 module and a set of transformers (and shunts for the 1050MW substations).

A module is a steel building which houses the main electrical infrastructure, that will be fabricated and assembled onshore (similar to an offshore topside but without transformers). The modules will be supported by means of an open concrete cellar, which allows the routing of cables. One of the modules will be equipped with a helideck.

The switchgear will be installed in these AC modules. The transformers will be installed on the land area on a concrete plate and inside a shelter. Besides the switchgear, there are rooms foreseen for utilities, control and protection cabinets and 1 room for each OWF. The land area will be protected from intruders by means of wave walls and fences. The land area shall be accessible from the quay area and Crew Transfer Vessel (CTV) harbor by means of gates.

2.6.2. Drainage buffer zone

Three sides of the energy island will be ‘exposed’ (north, south, west) with high primary wave walls to limit overtopping of sea water. The drainage buffer zone is situated behind the wave wall to catch and drain overtopping water towards the eastern (sheltered) side of the Island. This zone is allowed to be flooded and will have a high drainage capacity during storm conditions. The secondary wave wall will prevent or minimize overtopping of the land area where the grid infrastructure is located. The sheltered eastern side does not require an outer wave wall. Due to the sheltered location the quay and entrance to the Crew Transfer Vessel (CTV) port (northeast side) are located here as shown on Figure 24.

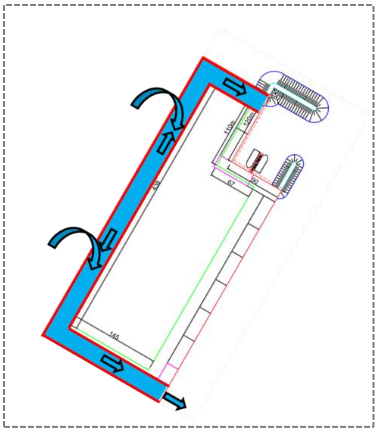


Figure 24 : Drainage buffer zone in the Princess Elisabeth Island

2.6.3. Quay side

A quay side is foreseen at the east side of the island and is foreseen to allow mooring of supply vessels as well as transport & installation (T&I) vessels. For the offloading of supply vessels a crane with a capacity of 6 ton and the crane position shall ensure lifting activities can be performed both while CTV is moored at the jetty and while CTV is pushing against the boat landing.

2.6.4. Crew Transfer Vessels harbour

The PEI contains a harbour equipped for Crew Transfer Vessels (CTVs). This harbour consists of:

1) A floating jetty which allows the mooring of 2 CTVs;
2) A crane to offload CTVs with a capacity of 6 ton;
3) A boat landing.

2.7. Cable routing and pull-in

2.7.1. Cable routing around Princess Elisabeth Island

The cables will be grouped in corridors per Offshore Wind Farm concession. As shown on Figure 25 below, there will be a separation between the different corridors. The space left in between the different corridors is left open intentionally to allow for future interconnectors and is considered as a separation zone between the different stakeholders. The space between the cable corridors and windfarm concessions is an official safety zone. Currently, no offshore crossings within close proximity of the island are foreseen. However, offshore crossings cannot be avoided for future interconnectors. The location of the concessions and cable corridors are shown in Figure 25 and Figure 26.

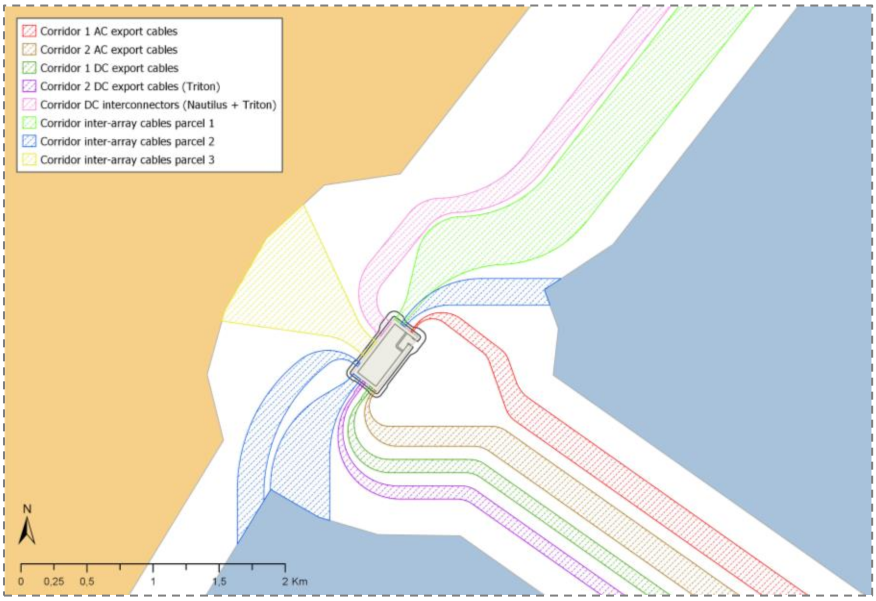


Figure 25 : Drawing of routing around island

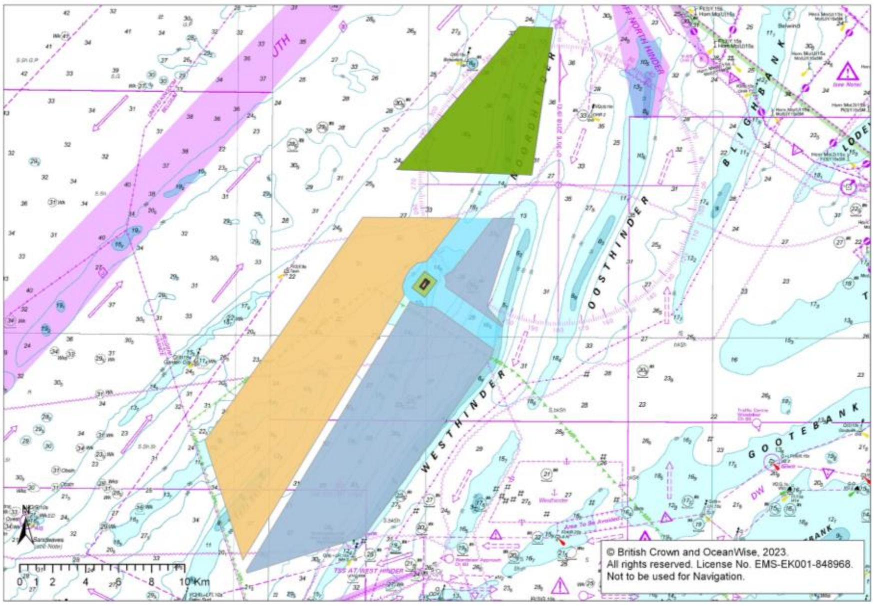


Figure 26 : The location of the concessions and cable corridors

2.7.2. Cable approach

The island outer perimeter will consist of concrete caissons placed on the seabed. A scour protection will be applied around those caissons. The area inside the caissons will be filled with sand.

The inter array cables will be guided from the OWF towards the island by passing over the scour protection. As the cable will be installed on the scour protection, a cable protection system should be applied.

The cables will pass through the island boundaries or concrete caissons by means of J-tubes as shown in Figure 27. The J-tubes design is standardized to accommodate all types of cables. A J-tube is similar to a monopile entry hole. It has two entry holes above each other to accommodate for installation tolerance of the scour protection. The cell of the caisson containing J-tubes (the so called first cell of the caisson) will be filled with water to optimize the thermal behavior of the cables. The J-tube inner diameter will be 750mm. The design pull-in load will be 300 to 400kN. The inter array cables will subsequently be routed to the GIS of different modules.

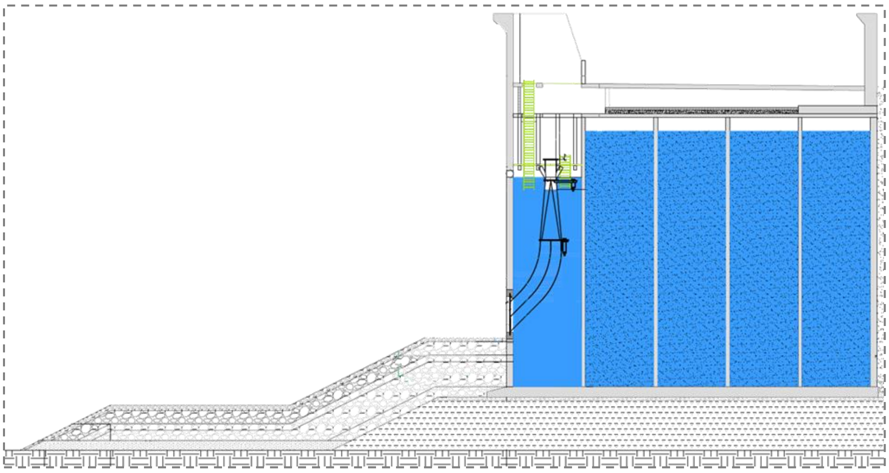


Figure 27 : Visualization on a J-Tube inside the caisson

2.7.3. Cable pull-in concept

A cable pull-in is done to initiate or finalize the cable installation over a cable route. The submarine cables are to be pulled into the energy island through the foreseen J-tubes. The J-tube ends in the hang-off room where the submarine cable can be fixated. A designated length of cable is pulled onto the island. The cable will be terminated on the island for final connection to the GIS cable compartment. The possibility exists to connect the offshore cable to an island cable by means of a joint in the drainage buffer zone under the responsibility of the OWF. The cable hang-off will be in the “hang-off room” which is positioned in the upper part of the first cell of the concrete caisson as shown in Figure 28. The hang-off room will be a confined space but not air-tight. A concrete lid will be installed to seal the hang-off room. This lid can be removed by crane for cable pull-in to allow the pull-in system (e.g. tripod) to be placed above the J-tube. Personnel can access the hang-off room by means of a manhole with a ladder.

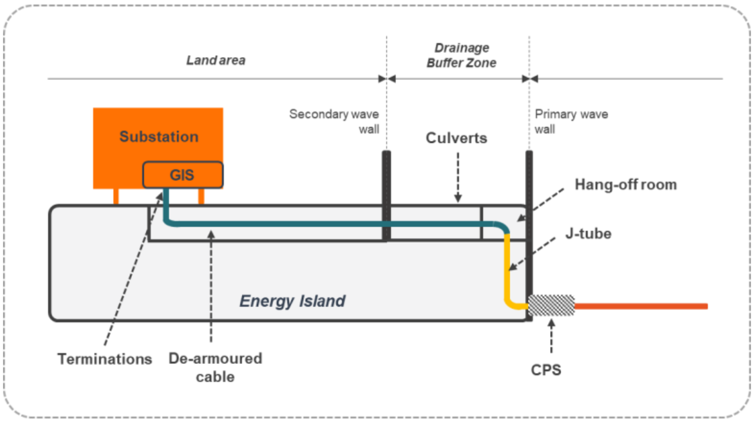


Figure 28 : Hang-off room in the Princess Elisabeth Island

2.7.4. Routing on the Princess Elisabeth Island

A designated corridor will be attributed to each offshore wind farm concession to route their cables. Cables will be routed through the secondary wave wall via watertight cable transits. The cables will be routed on the island inside concrete culverts from the secondary wave wall towards the GIS inside the dedicated AC substation. Culverts will have lids that can be removed for easy access. Figure 29 aims at visualizing a preliminary layout of the cable routing on the PEI, showing the principles of working with corridors. The cable routing on the PEI is still evolving and the corridors are subject to change.

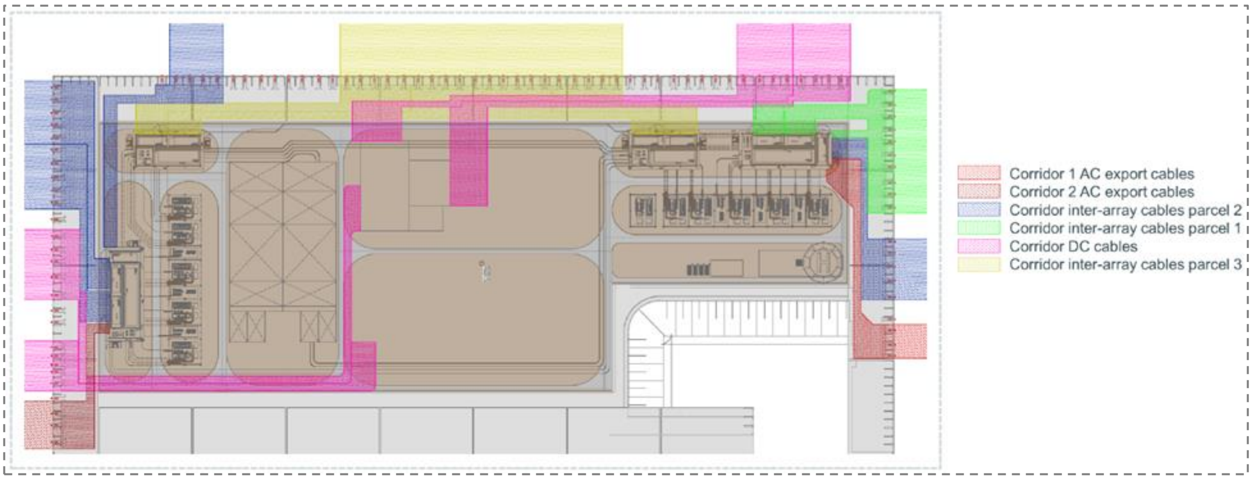


Figure 29 : Preliminary view on the routing of the Princess Elisabeth Island

2.7.4.1 Culverts in land area

Elia will provide concrete culverts in the Land Area to route the cables of the OWF to the HVAC Modules. In the reinforced zones on the Land Area (zones are reinforced to allow crossing of roads) concrete culverts with a concrete lid will be installed. In the non-reinforced zones of the Land Area concrete culverts covered by Fiber Reinforced Panels (FRP) lids might be installed.

The proposed design specifications for the concrete culverts on the Land Area are the following:

- Minimum inner width: 1m
- Minimum height: 1m
- Minimum thickness of concrete sides and bottom: 15cm
- Maximum thickness of concrete lids in the reinforced zones on the Land Areas: 15cm
- Maximum thickness of FRP lids in the non-reinforced zones on the Land Areas: 5cm

Thermal characteristics of the concrete: 1Km/W.
Lifting provisions will be foreseen on the concrete lids to be able to open the culverts.

2.7.4.2 Culverts in the drainage buffer zone

The design of the cable culverts in the drainage buffer zone is still evolving. The dimensions of the culverts in the drainage buffer zone will be non-restrictive compared to the dimensions of the culverts in the Land Area.

2.8. High voltage systems

The wind farm inter array cables (IAC) shall be connected directly in the cable compartment of the 66kV GIS bay. The type of GIS 66kV shall be a GE F35-CB31 with SF6 as the insulated gas type.

Property and maintenance border remains at GIS cable compartment, in accordance with IEC62271-209. The use of dry type cable terminations Um: 72,5kV is required.

Elia will provide the female part of the cable termination (GIS 66kV). Elia has standardized the type of the epoxy: Pfisterer HV-CONNEX, Size 4 (industry common practice). An installation in the GIS factory is envisaged. The OWF will provide the male part of the cable termination (cable 66kV). The OWF must qualify the male part with Pfisterer (EN-60840). Elia requests a plug-in installation of the inter-array cable as shown in Figure 30.

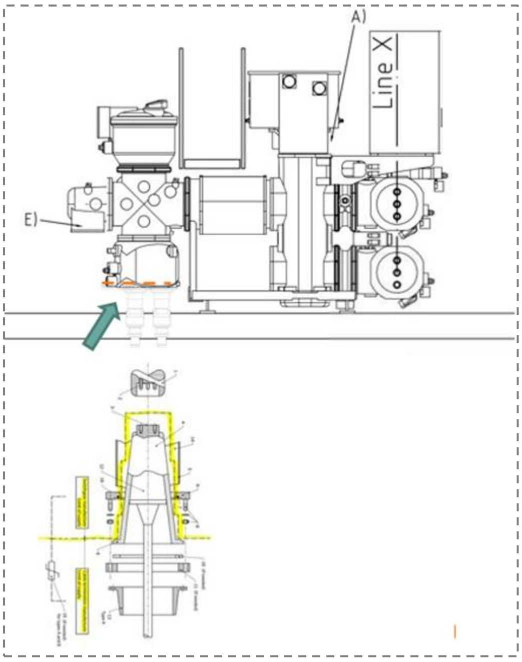


Figure 30 : Plug-in installation of the inter-array cable

The 3-phase short circuit current is 31,5kA on the connection point. The duration (trip time) is 1s. The 1-phase short circuit current is 4kA. The duration (trip time) is 1,2s. The coupling of the step-up transformers of the wind turbines is chosen such as to have (almost) no short-circuit current contribution from the wind turbines in case of a single-phase fault (yD). Impedance of the neutral point transformers (npt) has been chosen such that the total neutral current contribution equals 4kA on the 66kV busbar. Xnpt is between 40 and 50 ohms/phase for each neutral point transformer.

2.9. Secondary systems

2.9.1. Protection concept

Elia will protect the 66kV inter array cables with two distance protections and an overload protection. With the use of 2 distance protections and zone-specific criteria, Elia will be able to protect the complete cable excluding wind turbines. OWF protects each wind turbine by installing their own local protections. To limit the interface with the OWF Elia will not install an interface cubicle in the first wind turbine. There will be no tele-tripping order towards the wind turbine.

The distance protection will use 2 intelligent electronic devices with protection 1: GE P443 (as shown in Figure 31) and protection 2: GE P442. The OWF is allowed to use the low voltage cable protection as described above. However, the design and criteria specific to each zone will be defined and further elaborated upon during a collaborative planning phase involving Elia and the OWF. This will result in a joint scope and responsibility.

As shown in Figure 31, different zones in the distance protection P1 scheme are represented:

1) **Zone 1** has been used as a current criterion to avoid unwanted trips for backward faults. The justification follows the grid code and the wind turbines' Fault Ride Through (FRT) requirements;
2) **Zone 2** shall be substituted by a non-directional I0>t and a I>t – approximately 150ms criterion. The designated value shall be selective with the wind turbine protection system and compatible with the Fault Ride Through specifications;
3) **Zone 3**: approximately 0,95s (back-up);
4) **Zone p** (direction feeder): approximately 1,35s (back-up);
5) **Zone 4**: approximately 1,65s (back-up).

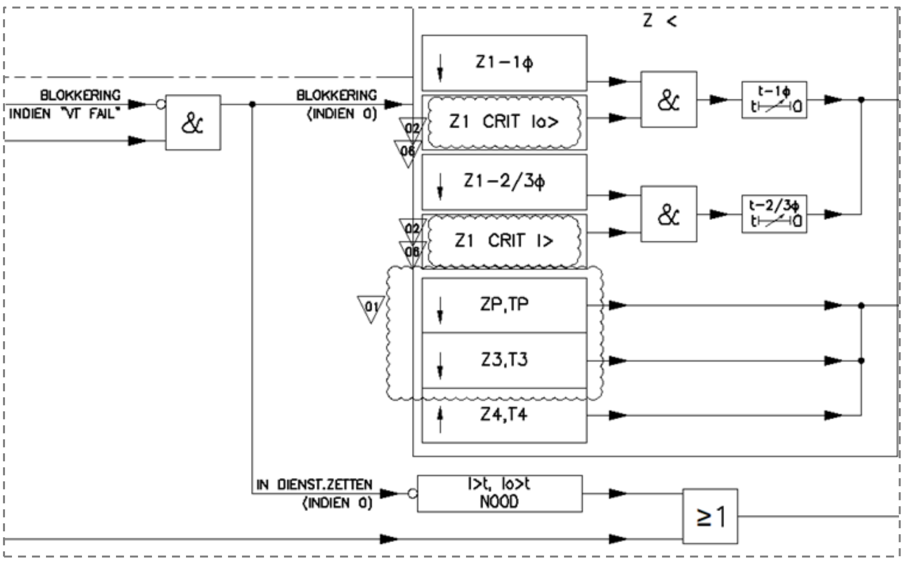


Figure 31 : Distance protection P1 - GE P443

2.9.2. Signal exchange

All systems that are critical for the operation of the substations and island signalization shall be transmitted to onshore Elia dispatching.

The list of signals to exchange between Elia and the OWF and the communication methods are synthetized in the interface list in Figure 32, Figure 33 and Figure 34.

For safety reasons Elia cannot allow a direct connection to a dedicated current transformer and voltage transformer. Therefore, Elia concludes to install a measuring convertor (Convertor) in a dedicated OWF cubicle for time critical purposes. Elia proposes the use of Elia validated convertors such as a SINEAX DM5S or DM5F or equivalent as shown in Figure 32. Interface can be set-up via several interfaces e.g. MODbus.

Device	Sineax DM5S	SIEMENS 7KG85	GE I5MT
Response time	85...165ms	200ms	100ms
Interface	Modbus/RTU (via RS485) 4 analoge outputs +/-20mA	Modbus/RTU Modbus/TCP IEC61850 IEC60870-5-103	Modbus/RTU Modbus/TCP 4 analoge outputs +/-20mA

Figure 32 : Comparison of measuring converter for OWF cubicle

Other measuring convertors can only be implemented when the minimum requirements have been fulfilled and validated by Elia. The requirements are:

1) extended current rating of 130% (1,3A);
2) continue thermic current of 150% (1,5A);
3) thermic resistance of 100A – 1s (minimum of 40A – 1s);
4) lifetime of the equipment of minimum 20 years;
5) software maintenance exclusively from onshore (remote);
6) redundancy.

For all scenarios described above the offshore wind farm will be responsible for the related equipment inclusive delivery, maintenance, support and spare parts management. For all other purposes, Elia provides protocol IEC104 via the RTU/DCS in scope of Elia towards the OWF interface cubicle in the OWF room.

To regulate the active power output, the Power Park Controller (PPC) shall be connected to each 66kV inter array cable bay. To regulate the reactive power output, the voltage control shall be linked to a measuring convertor of the transformer bay 66/66/220kV, side 220kV, as described in Section 3.4.

The inter-array cable bays will be equipped with a revenue counter for client invoicing. The counters will be provided and maintained by Elia. Elia will provide hard wired the real time counting impulses.

OWF per string ==> ELIA	From	To	Time Critical	Signal	Communication path
Stand kabelscheider IN	OWF	Elia	N	Position	IEC104
Stand kabelscheider UIT	OWF	Elia	N	Position	IEC104
Stand Kabelaarder IN	OWF	Elia	N	Position	IEC104
Stand Kabelaarder UIT	OWF	Elia	N	Position	IEC104
Spare	OWF	Elia			
Spare	OWF	Elia			
Spare	OWF	Elia			
Spare	OWF	Elia			
Spare	OWF	Elia			
ELIA ==> OWF per string					
Stand Vermogenschakelaar Elia IN	Elia	OWF	N	Position	IEC104
Stand Vermogenschakelaar Elia UIT	Elia	OWF	N	Position	IEC104
Stand Railscheider Rail 1 IN	Elia	OWF	N	Position	IEC104
Stand Railscheider Rail 1 UIT	Elia	OWF	N	Position	IEC104
Stand Railscheider Rail 1 geaard	Elia	OWF	N	Position	IEC104
Stand Railscheider Rail 2 IN	Elia	OWF	N	Position	IEC104
Stand Railscheider Rail 2 UIT	Elia	OWF	N	Position	IEC104
Stand kabelscheider Elia IN	Elia	OWF	N	Position	IEC104
Stand kabelscheider Elia UIT	Elia	OWF	N	Position	IEC104
Stand Kabelaarder Elia IN	Elia	OWF	N	Position	IEC104
Stand Kabelaarder Elia UIT	Elia	OWF	N	Position	IEC104
Stroommeting 66kV Elia	Elia	OWF	N	Measurement	Convertor
Spanningsmeting 66kV Elia	Elia	OWF	N	Measurement	Convertor
Actief -> (A+)	Elia	OWF	Y	Impuls	Hard wired
Actief -> (A-)	Elia	OWF	Y	Impuls	Hard wired
Ri+	Elia	OWF	Y	Impuls	Hard wired
Ri-	Elia	OWF	Y	Impuls	Hard wired
Rc+	Elia	OWF	Y	Impuls	Hard wired
Rc-	Elia	OWF	Y	Impuls	Hard wired
1/4h	Elia	OWF	Y	Impuls	Hard wired
Spare	Elia	OWF	N		
Spare	Elia	OWF	N		
Spare	Elia	OWF	N		
Spare	Elia	OWF	N		
Spare	Elia	OWF	N		

Figure 33 : Exchange list of signals for offshore wind farm per string to Elia and inversely

OWF PPC ==> ELIA	From	To	Time Critical	Signal	Communication path
Real time available active power (MW)	OWF	Elia	N	Measurement	IEC104
Current voltage control mode (V control droop, Q constant, PF mode)	OWF	Elia	N	Position	IEC104
Current active power control mode (Maximum available power, limited by ELIA, limited by	OWF	Elia	N	Position	IEC104
Current LFSM mode (LFSM-U on, LFSM U off, LFSMO on LFSMO off)	OWF	Elia	N	Position	IEC104
Current MW setpoint (in PPC)	OWF	Elia	N	Measurement	IEC104
Current MVAR setpoint (in PPC)	OWF	Elia	N	Measurement	IEC104
Windsnelheid (m/s)	OWF	Elia	N	Measurement	TASE2
Windrichting	OWF	Elia	N	Measurement	TASE2
Emergency Elia	OWF	Elia	N	Control signal	TASE2
Blackout Elia	OWF	Elia	N	Control signal	TASE2
Grid restoration Elia	OWF	Elia	N	Control signal	TASE2
Spare	OWF	Elia	N		
Spare	OWF	Elia	N		
Spare	OWF	Elia	N		
Spare	OWF	Elia	N		
Spare	OWF	Elia	N		
ELIA ==> OWF PPC					
Actief vermogen meting Elia (MW)	Elia	OWF	N	Measurement	IEC104
Reactief vermogen meting Elia (MVAR)	Elia	OWF	N	Measurement	IEC104
Spanningsmeting 220kV Elia (zal afhankelijk zijn op welke TFO de string aangesloten is)	Elia	OWF	Y	Measurement	Convertor
Host Offline	Elia	OWF	N	Alarm	TASE2
Setpoint MW - maximum allowed active power injection MW absolute value	Elia	OWF	N	Setpoint	IEC104
Setpoint MVAr	Elia	OWF	N	Setpoint	IEC104
Emergency Elia	Elia	OWF	N	Control signal	TASE2
Blackout Elia	Elia	OWF	N	Control signal	TASE2
Grid restoration Elia	Elia	OWF	N	Control signal	TASE2
Spare	Elia	OWF	N		
Spare	Elia	OWF	N		
Spare	Elia	OWF	N		
Spare	Elia	OWF	N		
Spare	Elia	OWF	N		

Figure 34 : List of signals exchange from offshore wind farm PPC to Elia

2.9.3. Telecom concept

Optical fibers will be hosted in the submarine cables from the onshore substation GEZEL to the offshore AC substations 1050MW. The optical fibers will be split for redundancy and a maximum of 48 (or 24 pair) fibers will be dedicated for the offshore windfarms.

The communication between Elia and the windfarms shall be done via fiber (only single-mode) or copper as shown in Figure 35, which will be part of the detailed design. The offshore AC substations shall have a single-mode trunk towards the interface cubicles in the OWF room to be able to interconnect the windfarms to an onshore location.

Elia is assessing the required space on the property of the onshore substation GEZEL to facilitate the installation of windfarm telecommunication systems. The offshore windfarm shall be responsible for the installation and operation of the necessary telecommunication equipment and consequently their shelter.

2.9.4. Auxiliary power supply

The 400/230Vac will be foreseen by two independent power supplies per lot AC substation (1050MW resp. 700MW). Each power supply will be able to cover the full load of an AC substation. The island will be equipped with a diesel generator to power the auxiliaries after black-out of the grid. A power supply of 2x 110Vdc and 2x 230Vac UPS will be provided by Elia for each lot per AC substation.

2.9.5. Windfarm room

Several signals shall be exchanged between Elia and the OWF, this shall be done by means of interface cubicles installed in the OWF room on the AC substation as shown in Figure 35. The dimensions of the cubicles shall be: 2200x800x600 (LxWxD). The design will include one technical room for each lot per AC substation with a maximum footprint of 8 x 5 m. Lifting and installation of the Windfarm cabinets shall be executed by Elia in supervision of the OWF.

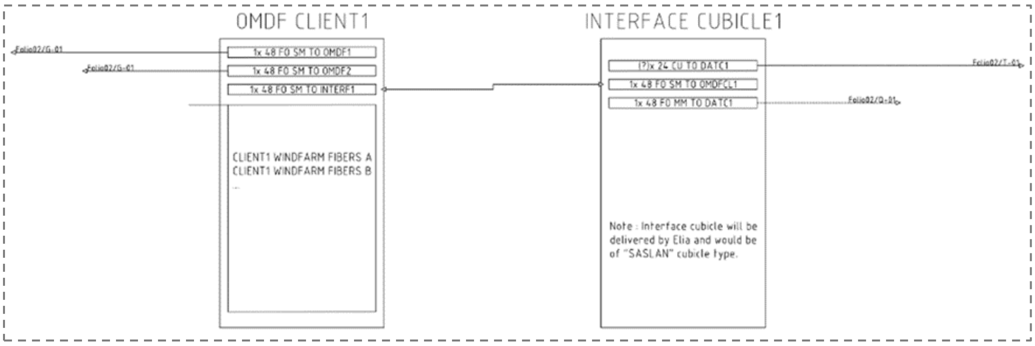


Figure 35 : Interface Elia – offshore wind farm lays in the cubicles

2.10. Marine and works coordination

2.10.1. Documents for Marine and Island Coordination

During the construction phase of OWF in Princess Elisabeth Zone, several documents should be submitted respecting a strict timetable to allow safe marine operations and/or island activities. As soon as (part of the concessions of) the OWF are operational, the conditions for OWF to access the PEI change towards a post commissioning phase. In order to grant permission for an OWF post-commissioning intervention, several documents must be timely submitted respecting pre-defined deadlines.

2.10.1.1 Documents prior construction

The documents to be transmitted by OWF owners to Elia in order to obtain permission to start the construction on the island will be requested in several phases according to a timeline (see Figure 36).

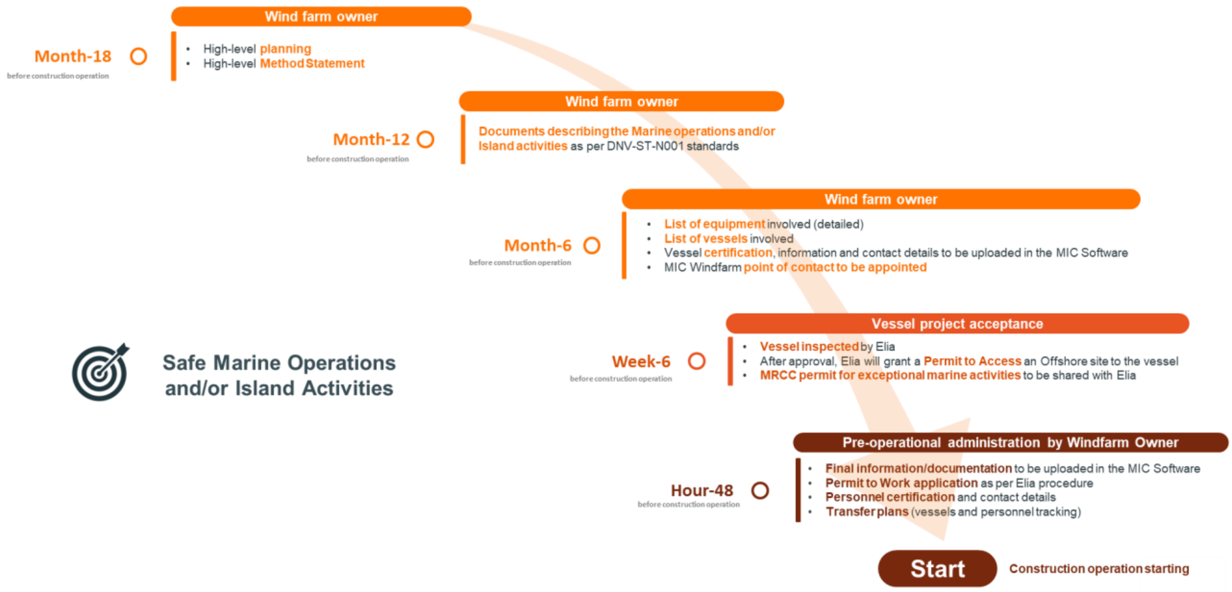
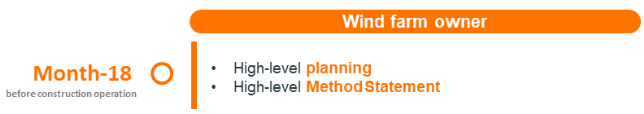


Figure 36 : Overview of documents to be provided prior construction phase

2.10.1.2 18 months prior start of construction operations

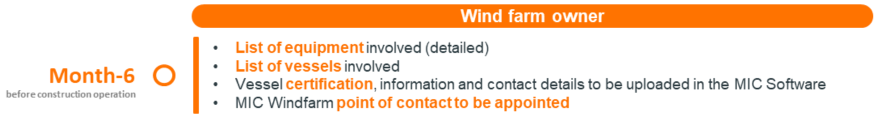


The OWF owner has to provide 18 months (1 and a half years) before the construction operations a high-level planning and high-level Method Statement to Elia.

2.10.1.3 12 months prior start of construction operations

One year prior to the construction operation, the OWF owner must provide documents describing the Marine operations and/or Island activities as per DNV-ST-N001. Those documents can be consulted in the DNV-ST-N001 standard under Section 2 Planning, 2.3 Technical documentation, 2.3.7 Marine operation manuals under 2.3.7.2.

2.10.1.4 6 months prior start of construction operations

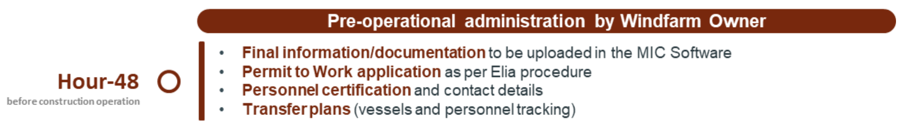


Six months before the construction operation starts a detailed list of involved equipment, a list of involved vessels and MIC windfarm point of contact must be transmitted to Elia. Simultaneously the vessel certification, information and contact details must be uploaded in the MIC Software.

2.10.1.5 6 weeks prior start of construction operations

Six weeks prior to starting the construction operations, the vessel project acceptance procedure will start. This procedure is explained in detail in Section *2.10.2.1*. The vessel requesting access will be inspected by Elia. After approval of the vessel, Elia will grant a Permit to Access an Offshore site. When the OWF owner obtains the MRCC permit for exceptional marine activities, it must be shared with Elia.

2.10.1.6 48 hours prior start of construction operations



Forty-eight hours prior to the start of the construction some pre-operational administration must be completed by OWF owner. The final documentation must be uploaded in the MIC Software. The Permit to Work application should be done as per Elia procedure. All personnel must be in possession of the proper certificates and their contact details must be up to date. Transfer plans (vessels and personnel tracking) must be available.

2.10.1.7 Documents prior O&M works after commissioning

As soon as the construction phase for (part of the concessions of) the OWF is completed and OWF is operational, the documents requesting access to PEI and the timeline for sending the documents changes. The procedure to request access to PEI is mentioned in Connection Agreement, Annex 10.

Every time a grid user requests to execute offshore infrastructure works; he must send a request hereto to Elia. In this request, he mentions minimum:

- **(a)** A description of the offshore works he wishes to execute (including a detailed description of the plan where on the offshore infrastructure the activities will take place);
- **(b)** The number of persons required to perform offshore activities and the identification of those people involved;
- **(c)** Whether the grid user requests to use the Elia material;
- **(d)** The expected duration of the offshore infrastructure activities that the grid user wishes to execute;
- **(e)** A proposal for beginning and end date for the execution of the offshore infrastructure works taking into account a reasonable margin of days for weather latency, of which the amount of days may be modified in good faith and with proper justification by Elia ('the access window');
- **(f)** Two alternative access windows must be provided in case the offshore operations cannot take place due to exceptional weather conditions within the access window specified in accordance with point (e).

Except in the case of urgency and subject to the express agreement by Elia, the user directs the request to Elia:

- **(a)** Minimum 42 days prior the first day of the access window;
- **(b)** Minimum 21 days prior to the first day of the access window if the offshore infrastructure activities wherefore a request was done only concern normal periodical maintenance and if the provided request contains all required information;
- **(c)** Minimum 10 days prior to the first day of the access window if the offshore infrastructure activities wherefore a request was done only concern visual inspections and if the provided request contains all required information.

2.10.2. Access to Island

2.10.2.1 Access given to a vessel

Each contractor engaged on the Princess Elisabeth Island project must upload detailed vessel information into the “employer’s marine and island coordination tool/software” in the interests of safety, marine and island coordination and emergency coordination. The timeline below (see Figure 37) details the steps to be undertaken to obtain permission for a vessel/unit working on or near to the Princess Elisabeth Island.

Figure 37 : Flow chart vessel

** Should the ETD or ETA be scheduled on a “non-business day” or a “non-business+1”, all the permits to access and/or Permit to Work should be prepared before the “non-business day”.*

A “permit to access an offshore site” will be granted to a certain vessel after having met the following criteria:

1) Windfarm vessel is approved under the Vessel Project Acceptance (VPA) procedure. To ensure vessels/units are “fit for purpose” and suitable to undertake their intended operations safely, the vessels that will be involved in the PEI project need to be approved by Elia;
2) Contact details and documents of the vessels have been uploaded to the marine and island coordination tool/software;
3) Information about the activity/operation has been provided to Elia;
4) MRCC permit for exceptional marine activities has been delivered.

The permit to access will only be approved by Elia. Prior entering an offshore site, a Dynamic Positioning (DP) vessel needs to complete her DP checklists. The vessel is obliged to confirm verbally to the MIC watch that the DP checklists have been completed and will forward those checklists to the MIC watch.

2.10.2.2 Access given to personnel

Before being allowed on the Island, personnel will need to meet the following criteria (see Figure 38):

1) Windfarm personnel certification (training requirements) and contact details to be uploaded to Marine and Island Coordination Software by the OWF. Training specifications will be detailed under 2.10.4. Training requirements;
2) Windfarm Personnel to follow the marine and island coordination site induction.
   - A site-specific induction will be created by the contractor to highlight any particular risks and control measures that those working on a specific site need to be familiar with. At least, the following topics will be covered: site rules, personal protective equipment, smoking policy, restricted areas, hot works, traffic management systems, site tidiness, fire prevention, permit-to-work system and emergency plan & arrangements.
   - Specific equipment induction will have to be provided by contractors to workers being involved in the equipment/modules (e.g. AC working area, DC working area, etc.);
   - The induction needs to be refreshed if the worker is not on site for 6 months.
3) Personnel to be approved in the Marine and Island Coordination (MIC) software.

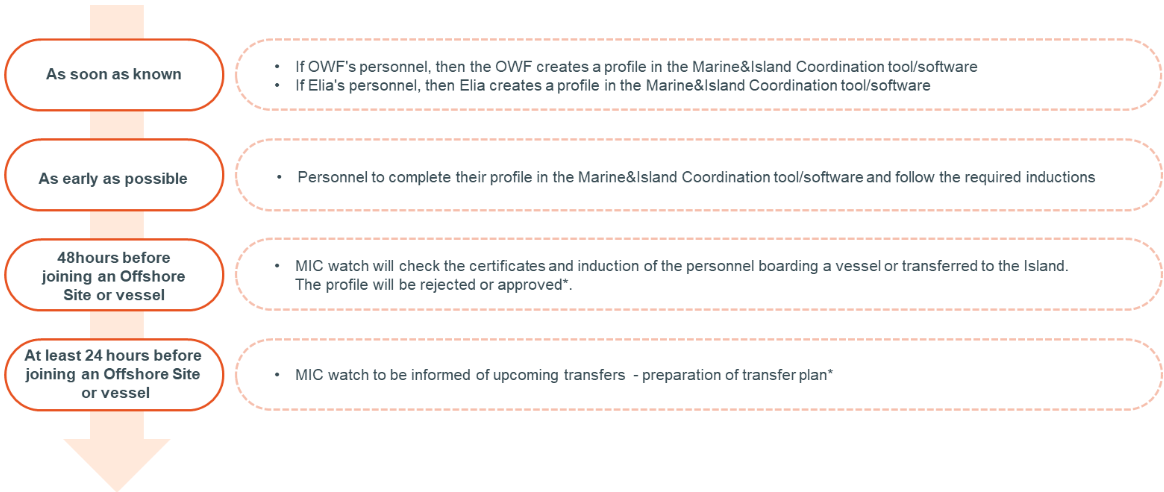


Figure 38 : Personnel workflow

2.10.3. ERCOP – ERP

In the event of an emergency at any stage of the “Princess Elisabeth Island project”, an initial response to the emergency will be started.

The initial response will follow the predetermined procedures detailed in Emergency Response Coordination Plan (ERCoP). This is a tool/guideline/procedure to prepare and coordinate the different parties during an Emergency (e.g. contractors, O&M, OWF, authorities etc.). It provides guidelines for the coordination and management of an emergency or a possible emergency. Every OWF is responsible for providing their own Emergency Response Plan (ERP).

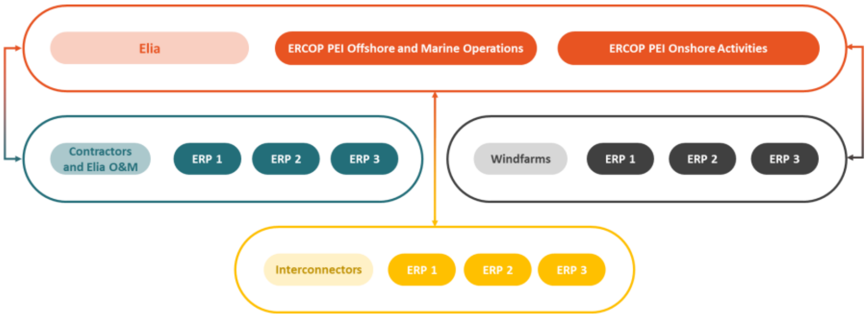


Figure 39 : ERCoP and ERP interrelations interaction

2.10.4. Training requirements

At all times, all personnel need to be appropriately certified, inducted and have submitted their Next Of Kin (NOK).

As mentioned under Section 2.10.2.2 “Access given to personnel”, before being allowed on a Marine and Island coordination site, personnel will need to have followed adequate trainings (site and transportation mode specific induction; offshore health certificate; BOSIET or GWO, GWO Advanced First Aid for 10% of the workforce, HUET + CA-EBS in case of transfer per helicopter, Elia Electrical training and BA4/BA5, task specific trainings as displayed in Figure 40.

Inductions and Medical fitness

- Induction (site specific and transportation mode specific)
- Offshore Health certificate

Certificates and training

- [BOSIET + Boat-landing] or GWO (Sea-survival including boat-transfer, First-aid and fire-fighting)
- GWO Advanced First Aid for 10% of the workforce
- Transfer per helicopter (HUET + CA-EBS)
- Elia Electrical training and BA5
- Based on tasks specific and risks assessments, extra trainings might be required (e.g.: Working at height, confined spaces,…)

Figure 40 : Training requirements overview

2.10.5. Process with respect RAMS

To avoid schedule interface issues, all parties have to submit the schedule of their works timely. Based on these inputs, Elia will develop consolidated schedule, in case of conflicts the relevant parties will be consulted. If conflict persists Elia will prioritize taken into consideration the impact of the different works (e.g., a cable pull-in will get priority over a seabed survey).

2.11. Operations & maintenance

The principles related to operations and maintenance are covered in the previous Section 2.10.

3. Dynamic & Harmonic

3.1. Executive summary

The production units that will connect to the Princess Elisabeth Island shall comply with the technical requirements as defined in the European Requirements for Generators Network Code (RfG NC), implemented in the Belgian law via the "Federal Grid Code" (FGC) and translated into technical requirements via the "General Requirements for Generators" by the Belgian Transmission System Operation Elia in the case of Belgium.

Following Article 110 §2 of the Federal Grid Code, the Transmission System Operator may introduce additional requirements applicable for offshore wind farms. The present document introduces the clarification of the requirements triggered by 'Dynamic & Harmonic' challenges to be followed by the offshore wind park for the Princess Elisabeth Zone tenders, on top of the technical requirements foreseen for such installation in the Federal Grid Code (i.e. type D Power Park Module (PPM)).

These requirements can be clustered into 4 main categories:

1. Active power forced oscillations;
2. Voltage management, MVAr capability and dynamic performance;
3. Data & model provision and validation;
4. Conformity process.

In general, the proposed amendments of the requirements applicable for offshore wind farms written in the Federal Grid Code are described based on the experience of existing offshore wind farms, to bring more clarity and certainty and/or avoid unnecessary costs for the wind park developer during the design, implementation and commissioning phase of the wind park installation.

Additional requirement related to active power forced oscillations

In the current European or national legislation, no reference at all exists regarding the notion of active power forced oscillation and regarding the criteria limiting their occurrence in the transmission power system. To avoid different and divergent interpretation as it was the case for the existing offshore wind farms in Europe, ENTSO-E with the support of European TSOs, among which Elia, and WindEurope, with the support of manufacturers, developed a common proposal of criteria as input for the upcoming update of the RfG NC. Elia's first assessments show that these new criteria can be met by existing offshore wind farms. It is anticipated that it should also be possible for new wind farms. It is therefore proposed to anticipate the legal process for the amendment of the RfG at EU level and to clarify these criteria for forced oscillation as additional requirements for the PEZ tenders. This provides further certainty for all bidders compared to a situation whereby these requirements would not be made explicit.

Clarification related to voltage management and MVAr capability

The clarifications made for the voltage management and MVAr capability required for OWF in PEZ is based on two main considerations:

1) The return of experience on real performance and capability from existing offshore wind farms in Belgium (MOG I);
2) The 66 kV connection voltage level for OWFs in PEZ, combined with the fact that they will be coupled to the Elia grid via a step-up transformer, which is neither managed nor operated by the OWF owner (in contrast to MOG I).

On this basis, it was concluded by Elia that some existing requirements or added new requirements to better cope with the way the installation can provide robustness to the transmission power system while limiting the impact on their cost.

In this spirit, following requirements have been improved or added:

- Reduction of the Q,U reactive power capability curve and adaptation of the voltage droop control capability;
- Introduction of explicit Overvoltage ride through capability;
- Clarification on the capability to remotely change control modes between reactive power, voltage droop or power factor;
- Clarification on the way a request of new reactive power setpoint sent by Elia should be implemented while keeping the installation operating in voltage droop mode;
- Clarification that fast dynamic reactive current injection might be deactivated.

Clarification related to data & model provision and validation

Inverter Based Resources[6] (IBRs) and synchronous generators have fundamentally different dynamic performance characteristics resulting in a difference in the overall power system dynamic performance. These differences will become more prevalent as IBR uptake increases in the power system. Reductions

[6] *Inverter Based Resources represents all source of electricity asynchronously connected to the electrical grid based on electronic power converter are usually mainly renewable energy sources.*

in system strength, inertia, damping of small-signal oscillations, fault levels, and other synchronous characteristics are the results of the transition from power systems with a dominance of synchronous generators to a system with very few synchronous generators online.

These changes in system characteristics have caused new and emerging power system phenomena, in particular the risk of adverse interactions among the control systems of multiple nearby IBRs. More concretely, “micro-second” timeframe phenomena will appear, that can be captured mainly with Electro-Magnetic Transient (EMT) simulations, while for existing power system phenomena mainly “millisecond-second” phenomena are present, and those can be captured with less complex Root Mean Square (RMS) simulations. Such phenomena either did not previously exist or when they did, they were much easier to identify and address, e.g., sub-synchronous control interactions between IBRs and series compensated lines. Changes in the power system and generation mix mean that these phenomena are likely to occur more often (as experienced in other countries), that they have the potential to impact a larger part of the power system, and that their impact will be greater than it used to be. This could potentially result in major supply disruptions if such phenomena are not understood and addressed pre-emptively.

It is then of utmost importance to be able to correctly assess the risks related to these new phenomena through adequate and accurate simulations. To perform accurate simulations, there is a need to collect and validate adequate data & model of installations connected to the Elia.

Section 3.9 describes the detailed data that each Power Generation Module (PGM) will have to provide depending on their type and source of energy generation as well as the different steps of the process that will be applied during the conformity assessment to collect and validate the Root Mean Square (RMS) and Electro Magnetic transient (EMT) model of the installation.

Clarification related to the conformity process

The conformity process is not new and is a legal obligation from the European Requirements for Generators Network Code (RfG NC). The current process is based on 3 different stages:

- Energization Operation Notification (EON) stage: based on compliance proof, data and model exchange and leading to the ability to energize the installation;
- Intermediate Operation Notification (ION) stage: based on RMS simulations on simplified (Single Machine Infinite Bus) grid model and leading to the authorization to connect and operate the installation;
- Final Operation Notification (FON) stage: based on a test and leading to the Final Operation Notification.

As explained above, the evolution of the transmission system with increasing penetration of large converter driven generation sources and decreasing synchronous generation is causing new and emerging power system stability phenomena that might affect the quality of the power and could potentially result in damage or life-time reduction of network or grid users' installation or major supply disruptions if such phenomena are not understood and addressed pre-emptively.

Awaiting a framework harmonized at EU level, the objective of the improvement of the conformity process is to ensure secure and stable operation of the Belgian transmission system, necessary to limit the risk of damage or life time reduction of grid user or network installations or severe disruption in the supply of energy, while securing a timely FON delivery process for each new connecting PGM, independently from the order they are connecting to the grid.

The proposal is considering a proportionate and balanced approach to fulfill to challenges related to:

1. Additional complexity of modelling and simulating some phenomena, which require EMT approach instead of RMS approach;
2. Respecting legal and regulatory obligation as well as property rights of the different parties;
3. Considering the impact of system and grid users' evolutions and not only focus on the expected time of connection of the PGM.

This improved conformity process, developed and discussed in the framework of the upcoming tenders for the Princess Elisabeth Zone, is meant to be generic and applicable in the future for any new connection request. The requirements are then made specific to the type of units to ensure setting appropriate requirements, depending on the characteristics of the installation.

The proposed improvements mainly concern:

1. Criteria to determine which type of simulations will be needed to prove conformity depending on the type and size of the installation and screening index accounting for the potential risk of interaction with nearby relevant assets;
2. Additional data and model exchanges between Elia and the Asset owner of the new installation and inversely;
3. A secure "cloud-based" platform to perform the wide-area network EMT-based simulation assessment in order to not compromise the property-rights of the different Original Equipment Manufacturers (OEMs) owning the model of the relevant assets, and
4. Principles and rules how to handle non-conformity situations, including clarification where and in which conditions the assets shall have an obligation to investigate solutions to mitigate potential system dynamic performance issues, without compromising his FON status.

3.2. Introduction

Belgian power system is experiencing an uptake of approximately 7 GW of power electronic-based devices including offshore wind farms (OWFs) in the coastal area and HVDC links, including connections to other countries such as Great-Britain (Nautilus) and Denmark (TritonLink). In addition, other parts of Belgian power system are experiencing increased uptake of battery energy storage systems (BESS), solar farms and onshore wind farms. Whilst each of these are often individually much smaller than the OWFs and HVDC links, when combined their aggregate size could be similar or even higher than a large OWF or HVDC link. Concurrent with all these developments, the number of online synchronous generators are decreasing with likely withdrawal of large nuclear plants under accelerated inverter-based resources[7] (IBR) uptake scenarios.

IBRs and synchronous generators have fundamentally different dynamic performance characteristics resulting in a difference in the overall power system dynamic performance. These differences will become more prevalent as IBR uptake increases in the power system. Reductions in system strength, inertia, damping of small-signal oscillations, fault levels, and other synchronous characteristics are the results of the transition from power systems with the dominance of synchronous generators to those with very few synchronous generators online.

These changes in system characteristics have caused new and emerging power system phenomena, in particular the risk of adverse interactions among the control systems of multiple nearby IBRs. Such phenomena either did not previously exist or when they did, they were much easier to identify and address, e.g., sub-synchronous control interactions between IBRs and series compensated lines. Changes in the power system and generation mix have meant that these phenomena are likely to occur more often (as experienced in other countries), will have the potential to impact a larger part of the power system, and their impact will be greater than it used to be. These phenomena will affect the quality and stability of the power system, potentially leading to damage or impact on the lifetime of grid user or network installations or unforeseen disconnection of grid elements that could potentially result in major supply disruptions if such phenomena are not understood and addressed pre-emptively. A testament to this widespread impact is the growing need for IBRs in real world applications to install devices such as synchronous condensers or perform control system tuning to avoid instabilities that would otherwise be encountered.

[7] *IBR represents all resources asynchronously connected to the electric grid and are either completely or partially through power electronics (wind, solar, HVDC, energy storage etc)*

Figure 41 illustrates the AC Power System stability phenomena including the new emerging ones resulting from IBR penetration.

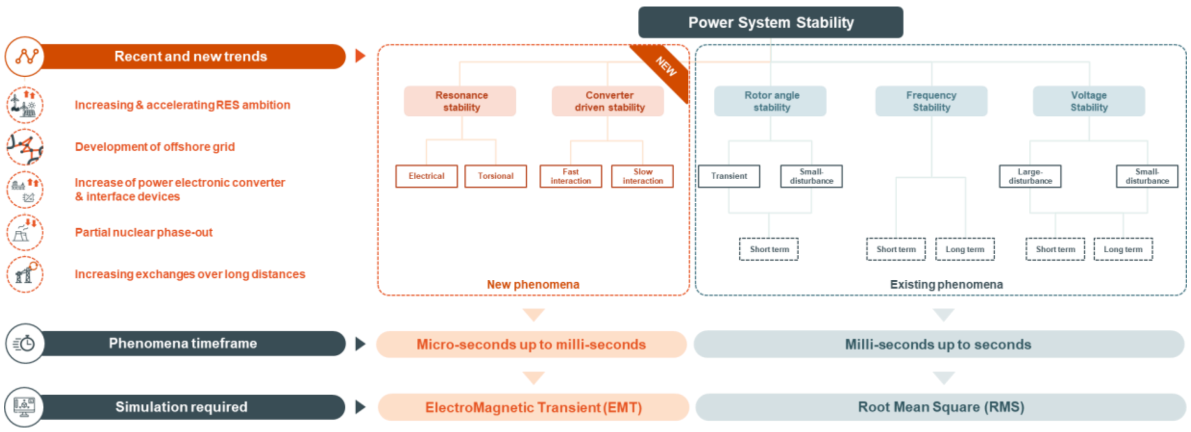


Figure 41 : Overview of Dynamic and Harmonic power system stability phenomena

Factors such as type of the Power Generation Module[8] (PGM), geographical location, individual and collective capacity size, proximity to synchronous machines and other IBRs influence the approach to be taken for conformity assessment, meaning that not all proposed connections can be assessed the same way, and that current practices adopted in Belgium and rest of the Europe may no longer be fit for purpose in some applications for the reasons discussed above.

The present chapter described the clarification of the requirements triggered by 'Dynamic & Harmonic' (Power System Stability) to be followed fulfilled by the offshore wind park for the Princess Elisabeth Zone tenders on top of the technical requirements foreseen for such installation in the Federal Grid Code (i.e. type D Power Park Module (PPM)) and can be clustered into 5 main categories:

1. Voltage management, MVAr capability and dynamic performance in Section 3.4 and 3.5;
2. Active power forced oscillations in Section 3.6;
3. Conformity process in Section 3.8.
4. Data & model provision and validation in Section 3.9;

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[8] *Power Generation Module represents all kinds of power generation asset (synchronous machine, battery storage, inverter-based sources, etc)*

Additionally, a clarification shall be provided by the TSO on “quick resynchronization and island operation” as requested in General Requirements for Generators. In the framework of the offshore tenders for PEZ, this requirement/capability is requested from offshore wind farm as described in Section 3.7.

In general, the proposed amendments of the requirements applicable for offshore wind farms written in the Federal Grid Code are described, based on the experience of existing offshore wind farms, to bring more clarity and uncertainty and/or avoid unnecessary costs for the wind park developer during the design, implementation and commissioning phase of the wind park installation.

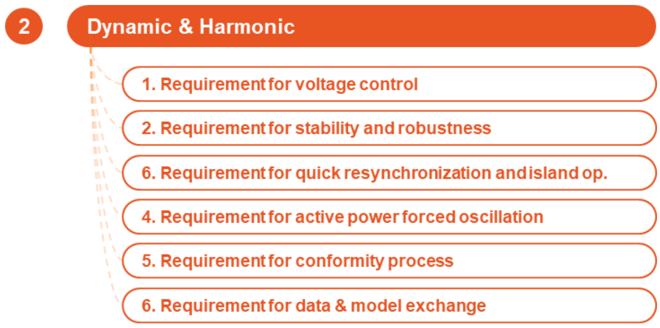


Figure 42 : Overview Dynamic & Harmonic topics

3.3. Standard and additional requirements

Each production unit shall follow the existing national regulation for generators, implemented in Belgium via the Federal Grid Code (FGC)[9] and the general requirements for generators[10]. As foreseen in the Art 110 §2 of the Federal Grid Code, the Transmission System Operator might introduce additional requirements applicable for offshore wind farms. The present document introduces the adapted requirements and relative technical reasoning to be followed by the PEI wind farms on top of the requirements for type D Power Park Module (PPM[11]) as described in the Federal Grid Code. Unless explicitly mentioned in the text, the requirements have been already presented and thoroughly discussed with the stakeholders during the Task Force Princess Elisabeth Zone and ad-hoc workshops meeting.

[9] *The Federal Grid Code* is available online: http://www.ejustice.just.fgov.be/eli/besluit/2019/04/22/2019012009/justel

[10] *The general RfG are* available online: https://www.elia.be/-/media/project/elia/elia-site/company/legal-framework/rfg.pdf

[11] *‘Power Park Module’ or ‘PPM’ means a unit or ensemble of units generating electricity, which is either non-synchronously connected to the network or connected through power electronics, and that also has a single connection point to a transmission system, distribution system including closed distribution system or HVDC system.*

The specificities of the PEZ offshore wind farms connection with Princess Elisabeth Island (PEI), together with the specificity of the installation calls for adapted requirements that aims on the one hand to optimize the design (and relative costs) and on the other hand to guarantee performances and stability of the installations in the complex reality of the PEI. They take into account already the comments raised during the stakeholder workshops[12]. For each amendment/clarification, an explanation is provided on the existing requirement, the new requirements, and the justification.

How the type of generation is defined in Belgian 'General Requirements for Generators'

The type of generation (Power Generating Module – PGM) is defined in the General Requirements for Generators as follow:

- **Type A:** 0.8 kW ≤ $P_{MAX}^{Capacity}$ < 1 MW and V_{cp} < 110kV
- **Type B:** 1 MW ≤ $P_{MAX}^{Capacity}$ < 25 MW and V_{cp} < 110kV
- **Type C:** 25 MW ≤ $P_{MAX}^{Capacity}$ < 75 MW and V_{cp} < 110kV
- **Type D:** 75 MW ≤ $P_{MAX}^{Capacity}$
  or 0.8 kW ≤ $P_{MAX}^{Capacity}$ and V_{cp} ≥ 110kV

With the following specific cases:

- Type D PGM having a 0.8 kW ≤ $P_{MAX}^{Capacity}$ < 1 MW will follow the same requirements as type A PGM
- Type D PGM having 1 MW ≤ $P_{MAX}^{Capacity}$ < 25 MW will follow the same requirements as type B PGM

Where

- $P_{MAX}^{Capacity}$ is the maximum (installed) capacity of the Power-Generating Modules (PGM);
- V_{cp} is the voltage level at the connection point.

As described in the General Requirements for Generators, the Power Park Modules (PPM), for which the connection point is located offshore should follow the same prescriptions as type D PPM units except if specifically defined in the document.

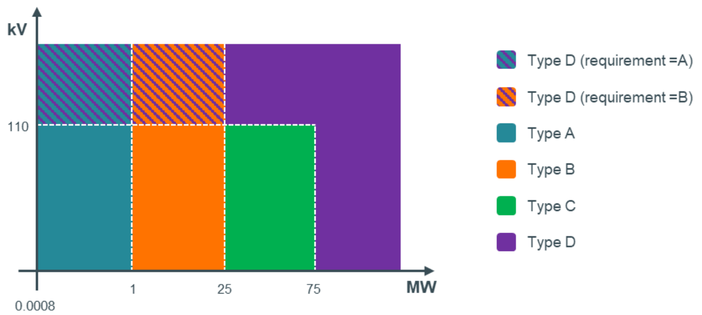


Figure 43 : Representation of the requirements to be followed by PGM depending on the proposed maximum capacity thresholds

[12] *The document relative to the Task Forces PEZ are available on Elia website:* https://www.elia.be/en/users-group/task-force-princess-elisabeth-zone/meetings

3.4. Clarification technical requirements for voltage control

3.4.1. Minimum injection and absorption of reactive power

3.4.1.1 Existing requirement

A PPM of type C and type D, including the Princess Elisabeth Zone offshore wind park, shall be capable to deliver reactive power within the Q-P profile[13] as follows, and as described in Figure 44:

- For any voltage at the Connection Point between 90 % and 110 % of the nominal voltage level (Unom) and for any value of the active power output between Pmin (equal to 0.2 pu of nominal active power (Pnom)) and Pnom, the PPM shall be able to produce or consume - at least - any reactive power at the connection point within the area limited by Q1, Q2, Q3 and Q4 as illustrated in the Figure 44;
- This range has an obligated minimum span of 0.6 per unit (pu) of Pnom, but can move within an area of [-0.3 pu of Pnom, +0.35 pu of Pnom];
- For all values between the 90% and the 110% for nominal voltage below 300kV voltage ranges (or 90% and 105% for nominal voltage above 300kV), it is requested that the PPM could participate in voltage regulation at least in the above mentioned reactive power range (as is represented in the U-Q/Pmax profile in Figure 44);
- For values outside of the 90% and the 110% for nominal voltage below 300kV (or 90% and 105% for nominal voltage above 300kV) voltage ranges, it is requested that the PPM could participate in voltage regulation to the maximum of the intrinsic technical capabilities of the installation;
- For any voltage value, at the Connection Point, between 90 % and 110% of Unom for nominal voltage below 300kV (or 90% and 105% for nominal voltage above 300kV) and for any value of active power output between P0 (equal to 0.0263 pu of Pnom) and Pmin, the minimum range of operating point for which reactive power shall be controlled is defined by the two values of the power factor computed by the points (Q1, 0.2*Pnom) and (Q2, 0.2*Pnom);
- For any voltage, at the Connection Point, between 90 % and 110 % of Unom for nominal voltage below 300kV (or 90% and 105% for nominal voltage above 300kV) and for any value of active

[13] *Extract from the document "Rfg Requirements Of General Application" – 22/08/2019*

power output below P0, the reactive power can be uncontrolled, however, injected/absorbed values must be limited within a range of Q = [-0.0329;+0.0329] pu of Pnom that is represented by the shaded area in the Figure 44;

- For specific voltages at the connection point, the required reactive power capabilities are smaller as represented in the U-Q/Pmax characteristic of Figure 45.

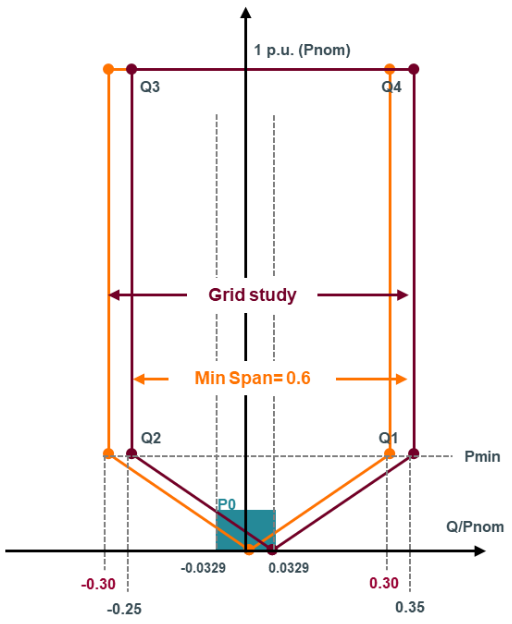


Figure 44 : Existing requirement for type C and D PPM for the reactive power capability vs active power

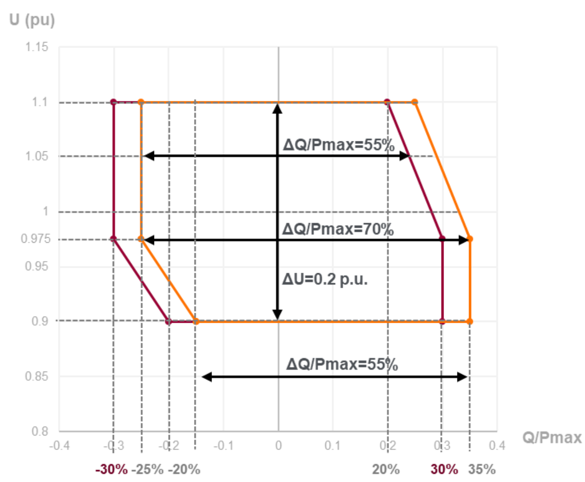


Figure 45 : Existing requirement for type C PPM for the voltage vs reactive power capability

In case of non-availability of units within the PPM due to failure or maintenance, the reactive power capability might be adjusted based on the current Available Generation Capacity P_{av} instead of Pnom (1 pu as per the figure above) which is expressed as following:

$$P_{av} = \sum_{i=1}^{N} av_i \times P_i$$

Where

- N is the number of installed units in the PPM;
- av_i is the availability factor of a unit i (either 0 or 1);
- P_i is the production capacity of a unit i during the failure or maintenance.

Note that the available capability of the PPM (which could be wider than the minimum requirement) should be communicated, demonstrated, and put at disposal of the relevant system operator.

The PPM owner shall not unreasonably withhold consent to use wider reactive capabilities, taking into account of their economic and technical feasibility. The unit is therefore expected to not limit its capabilities to comply with the minimum requirement but to use the full capability to support the system stability as stated in its agreement. The speed of reaction within the capability curve is site specific and will be determined during the connection conformity process (e.g., EDS) and specified in the contractual agreement.

3.4.1.2 Reason for modification and expected impact on the design

The main differences with the existing wind park are that the Princess Elisabeth Zone offshore wind farm connection point is on the 66kV (instead of 220kV behind a transformer) and that the wind farms will not own a platform on which additional reactive power compensation devices or transformers can be installed. The choice of a different voltage level has the following consequences:

1) The string array cable will be more capacitive (66kV) than the MOG 1 (33kV);
2) The voltage along the string will be more variable than the one on MOG 1 due to the capacitive behavior of the cable (quadratic w.r.t. the voltage level).

A string with the same number of wind turbines and the same length will be more difficult to compensate and the management of the voltage will be more difficult at 66kV (PEI) than at 33 kV (MOG 1) at off-nominal voltages.

Modern wind turbines have limitations on the voltage range for which they can control reactive power due to physical limitations in the converters. Beyond this operating voltage range (usually +/- 5% of the nominal voltage), the wind turbines are no more able to fully control the reactive power and may also disconnect in extreme cases.

As a matter of example if the voltage at the connection point is 1.05 pu, the voltage at the different wind turbines, depending on the operational state will be higher than this value if the park is injecting reactive power, and can go outside the operational area guaranteed by the wind turbine manufacturer.

Existing wind farms (MOG 1) are able to comply with the existing above-mentioned requirements because they use a transformer with online tap-changer that allows to keep the string voltage ‘seen’ by the wind turbines within a narrow range around 1 pu of voltage for any voltage at the connection point

(220kV). This will not be the case with the PEI wind farms for which the voltage will be imposed by Elia at the connection point 66kV.
In the PEI, the wind park owner will not build a platform and will not be able to install additional assets (i.e., transformer) to comply with the +/-10% pu range existing requirement.

For the reasons above, the requirement will be made less conservative by reducing the range of voltage at the connection point to a value of +/-5% of the nominal one and the Q-V curve will be adapted to give full capability within the expected steady state voltage at 66kV (i.e., controlled between +/- 1% of the nominal value) and limited one outside this range.

The new requirement is confirmed by a study that has shown the capability curve that can be obtained by the wind farms using the intrinsic capabilities of the wind turbines, i.e. without the need of installing additional assets or oversizing the wind turbine converters.

3.4.1.3 New requirement

The adaptations foreseen for the PEZ tender is highlighted below **in bold** while old description are ~~striketrough in red~~.

A ~~PPM of type C~~ **PEI wind park** shall be capable to deliver reactive power within the Q-P profile described in Figure 46 **and U-Q/Pnom profile in** Figure 47.

For every voltage at the Connection Point between ~~90 %~~ **95%** and **105%** ~~110 %~~ of U_{nom} **(66kV)** and for any value of the active power output between P_{min} (0.2 pu of P_{nom}) and P_{nom}, the PPM shall be able to produce or consume - at least - any reactive power at the connection point within the area limited by Q1, Q2, Q3 and Q4 (Figure 46) **taking into account the U-Q/Pnom curve of** Figure 47**.**

This range has an obligated minimum span of 0.6 pu of P_{nom}, but can move within an area of [-0.3 pu of P_{nom}, +0.35 pu of P_{nom}] when accepted by Elia, based on the connection point, size and the characteristic of the installation.

For all values between the ~~90%~~ **95%** and **105% of U_{nom} (66kV) taking into account the U-Q/Pnom curve of** Figure 47 ~~110% for nominal voltage below 300kV (or 90% and 105% for nominal voltage above 300kV) voltage ranges~~, it is requested that the PPM could participate in voltage regulation at least in the above mentioned reactive power range (as is represented in the **U-Q/Pnom** ~~U-Q/Pmax~~ profile in Figure 47) ; for values outside of the ~~90%~~ 95% and **105% of U_{nom} (66kV)** ~~110% for nominal voltage below 300kV (or 90% and 105% for nominal voltage above 300kV)~~ voltage ranges, it is requested that the **PEI**

wind park ~~PPM~~ could participate in voltage regulation to the maximum of the technical capabilities of the installation.
For every voltage value, at the Connection Point, between ~~90 %~~ **95%** and ~~110%~~ **105% of U_{nom} (66kV) taking into account the U-Q/Pnom curve of** Figure 47 ~~for nominal voltage below 300kV (or 90% and 105% for nominal voltage above 300kV)~~ and for any value of active power output between P_0 (equal to 0.0263 pu of P_{nom}) and P_{min} **(equal to 0.2 pu of P_{nom}) the** minimum range of operating point for which reactive power shall be controlled is defined by the two values of the power factor computed by the points (Q1,0.2*P_{nom}) and (Q2, 0.2*P_{nom}).

For every voltage~~,~~ at the Connection Point~~,~~ between ~~90 %~~ 95% and ~~110%~~ **105% of U_{nom} (66kV) taking into account the U-Q/Pnom curve of** Figure 47 ~~for nominal voltage below 300kV (or 90% and 105% for nominal voltage above 300kV)~~ and for any value of active power output below P_0, the reactive power can be uncontrolled, however, injected/absorbed values must be limited within a range of Q = [0.0329;+0.0329] pu of Pnom that is represented by the shaded area in the Figure 46.

~~For~~ **Depending on the** voltages at the connection point, the required reactive power capabilities are ~~smaller~~ represented in the **U-Q/Pnom** ~~U-Q/Pmax~~ characteristic of Figure 47.

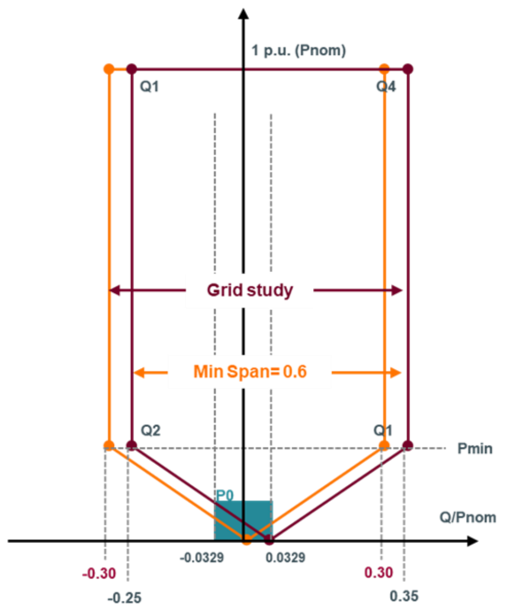


Figure 46 : Requirement (equal to the existing one) for type C PPM for the reactive power capability vs active power

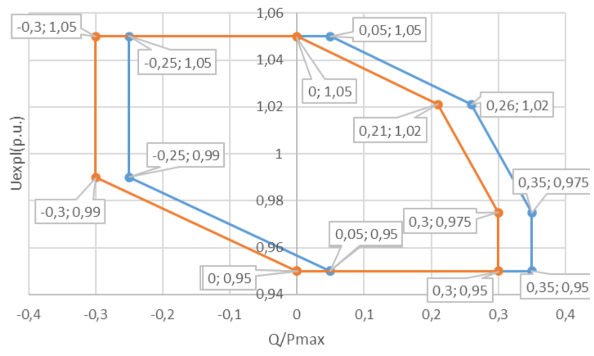


Figure 47 : New requirement for type C PPM for the voltage vs reactive power capability

In case of non-availability of units within the PPM due to failure or maintenance, the reactive power capability might be adjusted based on the current Available Generation Capacity P_{av} instead of P_{nom} which is expressed as following:

$$P_{av} = \sum_{i=1}^{N} av_i \times P_i$$

Where

- N is the number of installed units in the PPM;
- av_i is the availability factor of a unit i (either 0 or 1);
- P_i is the production capacity of a unit i during the failure or maintenance.

Note that the effectively available capability of the PPM (which could be wider than the minimum requirement) should be communicated, demonstrated, and put at disposal of the relevant system operator.
The PPM owner of the installation shall not unreasonably withhold consent to use wider reactive capabilities, taking account of their economic and technical feasibility. The unit is therefore expected to not limit its capabilities to comply with the minimum requirement but to use the full capability to support the system stability as stated in its agreement.

The speed of reaction within the capability curve is site specific and will be determined during the connection conformity process and specified in the contractual agreement.

3.4.2. Change of the voltage control droop principle

3.4.2.1 Existing requirement

A PPM of type C and type D, including Princess Elisabeth Zone offshore wind park, must be able to adapt its reactive power injected at the connection point[14]:

- Automatically in case of slow or fast variations of the grid voltage. This has to happen according to a reactive droop;

[14] *Extract from "RFG Requirements for General Application" – 22/08/2019*

- Through change of the controller set-point on request of the Transmission System Operator. This request is quantified in MVAr measured at the connection point. The change of set-point shall be initiated immediately after reception of the request;
- Reactive power exchange with the TSO network to control the voltage covering at least the 0.90 to 1.10 pu voltage range should be in steps not greater than 0.01 pu;
- The reactive power output shall be zero when the grid voltage value at the connection point equals the voltage setpoint as shown in Figure 48 below.

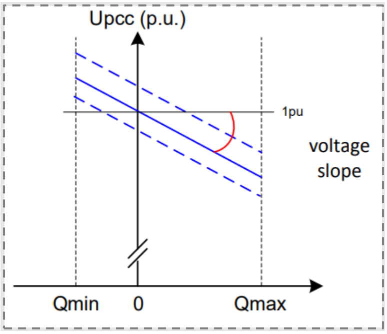


Figure 48 : Illustration of the existing curve for voltage-droop functionality.

The droop will be agreed between the Transmission System Operator and the PGM operator (before first energization) so that $\propto_{eq}$ lies between 18 and 25, as expressed in the following formula:

$$\propto_{\mathrm{eq}} = -\frac{\left(\frac{\Delta \mathrm{Q_{net}}}{0.45 \text{ x } \mathrm{P_{nom}}}\right)}{\left(\frac{\Delta \mathrm{U_{net}}}{\mathrm{U_{norm,exp}}}\right)}$$

Where

- U_{net} is the voltage measured at the Connection Point;
- $U_{norm,exp}$ is the normal exploitation voltage at the Connection Point;
- Q_{net} is the injected reactive power measured at the Connection Point;
- $P_{nom}$is the nominal capacity of the PPM.

The $\propto_{eq}$values can be transformed and are hence totally in line the value of a slope having a range of at least 2 to 7% as is mentioned in RfG art. 21.3d(ii).

3.4.2.2 Reason for modification and expected impact on the design

With the proposed new voltage control strategy, the voltage at the connection point (66kV) will no longer follow the grid voltage but will be maintained as constant as possible by the tap changer of the 220kV/66kV transformer.

As consequence the wind park would have been made insensible to a change of grid (i.e. 220kV) voltage and would not have been able to contribute to the system voltage stabilization as it would have 'seen' an almost constant voltage independently from the system voltage. The contribution of the wind farms is however fundamental to maintain system voltage healthy.

For this reason, the voltage to which the wind park will have to react is no more the 66kV one but will be the one of the high voltage (HV) side of the transformer to which they are connected (220kV).

The stability and feasibility of this change has been broadly studied and has been discussed with wind park manufacturers and stakeholders at large. In addition, a dead band is included to the voltage droop curve; this is already implemented in the current wind farms as default functionality and as consequence does not impact their control design.

3.4.2.3 New requirement

The Princess Elisabeth Zone offshore wind park shall be able to adapt its injection of reactive power at the connection point (Q 66kV) when a change in voltage happen at the HV side of the Three-Winding-Transformer (3WT) to which it is connected (V 220kV) according to a droop curve as shown in the Figure 49. To allow this, the measure of the 220kV side of the 3WT to which the offshore wind park is connected is made available to the wind park controller by Elia. A dead band function is added to the curve to allow robustness and limit potential interaction with other offshore wind farms.

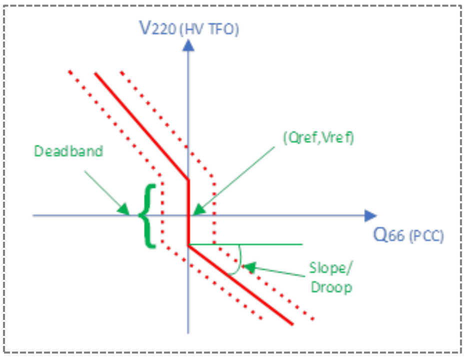


Figure 49 : Illustration of the new voltage-droop control requirement

The control should be made:

- Automatically in case of slow or fast variations of the grid voltage. This must happen according to a reactive droop/slope curve;
- Through change of the controller set-point on request of the Transmission System Operator. This request is quantified in MVAr measured at the connection point. The change of setpoint shall be initiated immediately after reception of the request;

- Reactive power exchange with the TSO network to control the voltage covering at least the reactive range should be in steps not greater than 1 MVAr.

The droop will be agreed between the Transmission System Operator and the wind park operator (before first energization) so that $\propto_{eq}$ lies between 18 and 25, as expressed in the following:

$$\propto_{eq} = -\frac{\left(\frac{\Delta Q_{net}}{0.45\ x\ P_{nom}}\right)}{\left(\frac{\Delta U_{net}}{U_{norm,exp}}\right)}$$

Where

- $\mathrm{U_{net}}$ is the voltage measured and transmitted to the wind farms (HV side of the 220kV/66kV/66kV transformer);
- $\mathrm{U_{norm,exp}}$ is the normal exploitation voltage of the (HV side of the 220kV/66kV/66kV transformer);
- $\mathrm{Q_{net}}$ is the injected reactive power measured at the Connection Point;
- $\mathrm{P_{nom}}$ is the nominal capacity of the PPM.

The $\propto_{eq}$values can be transformed and are hence totally in line the value of a slope having a range of at least 2 to 7% as is mentioned in RfG art. 21.3d(ii).

3.4.3. Offshore wind farm behaviour for reactive power set-point reception

3.4.3.1 Existing requirement

No detailed requirement has been defined in the existing Federal Grid Code (FGC) or Requirement for General Application (RfG).

3.4.3.2 Reason for modification and impact on the design

The absence of this requirement can bring uncertainty and additional costs for the wind park developer during the implementation and commissioning phase of the wind park control system. The impact on the design is minimum as this functionality has been already implemented for the MOG1 wind farms.

3.4.3.3 New requirement

The wind power park controller shall be able to receive a MVAr setpoint. When the setpoint is received, the wind park controller shall immediately switch control mode towards Q- reactive control mode and adapt its reactive power injection at the connection point to the newly received MVAr setpoint value. Once the set-point is reached, the wind power controller shall return to the voltage control mode that was active before the receival of the MVAr set-point.

3.4.4. Possibility to remotely switch the reactive power control mode

3.4.4.1 Existing requirement

There is currently no specific requirement relative to the remote change of reactive power control mode in the Federal Grid Code (FGC) or the Requirement for General Application (RfG).

3.4.4.2 Reason for modification and expected impact on the design

In specific conditions (e.g., loss of transformer, operation in antenna on the HVDC), the control mode of the wind park shall be modified. The modification of control mode is a normal functionality of all the power park controllers currently on the market but is currently performed by an operator on the wind power park control console.

To allow faster change of control mode (i.e., without human intervention of the wind park operator) it is required to allow an automatic remote change of control mode following a request from Elia.
It is considered that the addition of this functionality will not have major impact on the design of the wind park control system.

3.4.4.3 New requirement

The wind power park controller shall be able to switch reactive power control mode in an automatic and bump-less way following an instruction of the Elia control center between the following ones:

- Voltage droop control mode;
- Constant reactive power control mode.

3.4.5. Dynamical performances of automatic voltage control

3.4.5.1 Existing requirement

No dedicated requirement is present in the current version of the Federal Grid Code (FGC) or the Requirement for General Application (RfG).

3.4.5.2 Reason for modification and expected impact on the design

This requirement was present in the requirement for the MOG1 wind farms, but not present in the current version of the FGC. As the existing offshore wind park can comply with this requirement, it is considered that the new ones will be also able to comply as well without impact on their design or costs. It is added to increase clarity in the performance requirement of the offshore wind farms.

3.4.5.3 New requirement

For automatic voltage control and manual set-point change (on request of the Transmission System Operator), the response profile (Figure 50) of the controller has to fulfil the following requirements (where 1 p.u refers to the MVAr target value).

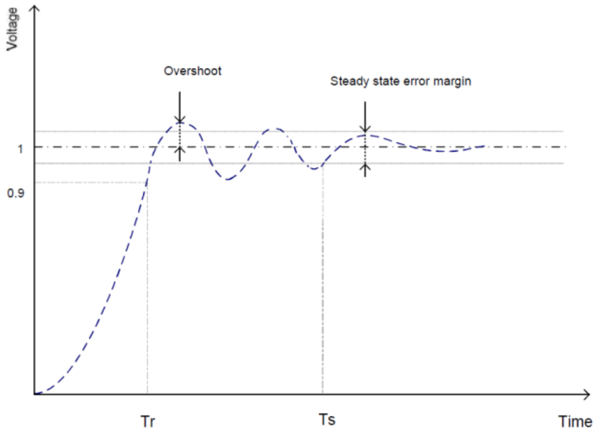


Figure 50 : Illustration of the dynamical performance of the voltage controller of a wind park

- The settling time Ts must be lower than 10 s. This time includes the reaction time 'Tr' in case of automatic voltage control;
- The reaction time Tr shall be in the range of 1~5 seconds and cannot be in conflict with the settling time requirement;
- The controller must ensure that the voltage at the Connection Point is controlled with a minimum accuracy of 0.5 % of the Unorm,exp (i.e. steady-state error margin of the voltage) or lower than 1 MVAr (at the connection point);
- The overshoot has to be as small as possible and, in any case, not be larger than the steady-state error margin;
- The steady-state reactive power control tolerance shall be not greater than 5 % of the full reactive power or 1 MVAr (the lowest one of the two);
- Setpoint change shall be achieved in steps not greater than 0.5% of the reactive range or 1 MVAr (the highest of the two);
- Damping ratio must be provided for any appearing oscillation higher than 5% as per small-signal stability compliance;
- Active and reactive power control should be decoupled (e.g. through automatic adaptation of the grid's R/X ratios).

3.5. Clarification technical requirements for stability and robustness

3.5.1. Capability to deactivate fast reactive current injection

3.5.1.1 Existing requirement

No dedicated requirement is present in the current version of the Federal Grid Code (FGC) or the Requirement for General Application (RfG).

3.5.1.2 Reason for modification and expected impact on the design

Depending on the system topology, it will be needed to disable the fast reactive current injection functionality between different mode of working (e.g. when connected to the DC side of the Princess Elisabeth Island (PEI) vs. when connected to the AC side of the PEI). The change of topology shall be performed in a reasonable time and for this reason it is proposed to allow the deactivation/activation of the fast reactive current injection via a command of the operator of the wind park (i.e. without the intervention of the wind park manufacturer).

Such a change of topology has to be foreseen to enable an evolution to a single node operation (see Section 2.3), but also to enable a certain flexibility in the operation of the Princess Elisabeth Island (e.g. change of topology could be considered in case of long lasting outages of some assets). No predefined scenarios are established considering the multiplicity of cases. Such changes of topology will require ad hoc discussions among the concerned parties and Elia.

3.5.1.3 New requirements

An offshore wind park connected to the PEI shall be able to deactivate the fast current injection via a functionality of the control system of the installation.

The disable/enable shall be performable remotely by the wind park operator, ideally during normal operation of the wind park (without restarting the installation).

3.5.2. High voltage fault-ride through

3.5.2.1 Existing requirement

No requirement for High Voltage Fault Ride Through (HVFRT) is currently presented in the Federal Grid Code (FGC) or Requirement for General Application (RfG).

3.5.2.2 Reason for modification and expected impact on the design

A high concentration of power-electronic based devices such as the offshore wind farms on the Belgian coastal area may cause, when subject to severe system fault, a temporary overvoltage (in the range of hundreds of milliseconds) at fault elimination. This over voltage is rapidly reduced and offshore wind farms are able to return to normal operation after it if they are able to withstand this temporary over voltage. An illustration of a simulated temporary overvoltage is shown in Figure 51.

Most of the recent wind farms are already compliant with this requirement. In addition, this requirement is already requested in other countries grid codes (e.g. German) and is foreseen to be included in the next EU NC RfG.

This requirement is considered to not have an impact on the cost as it is already a ‘de facto’ standard already implemented in commercial wind turbines and it enhances the system stability and robustness of the installation to voltage fast variations.

In fact, if the wind park would not be able to withstand the voltage profile, it would be disconnected causing a system unbalance and loss of revenues for the park itself.

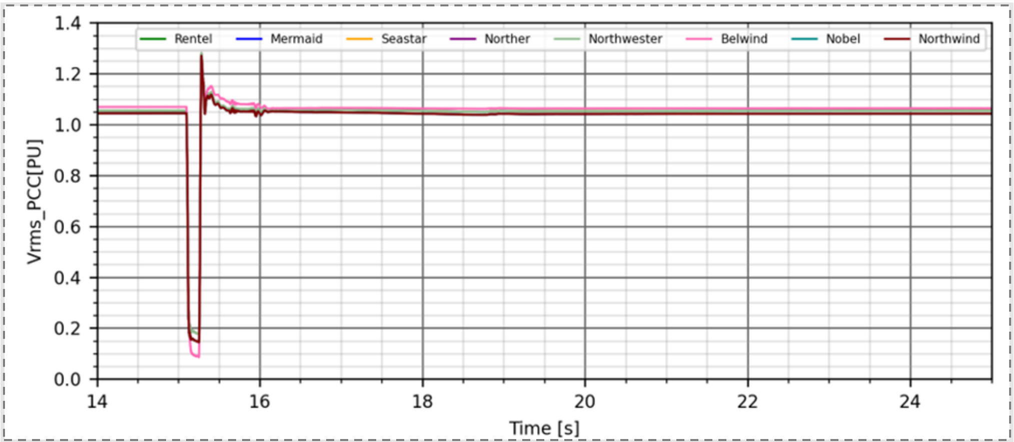


Figure 51 : Simulation of a temporary overvoltage as consequence of a system fault

3.5.2.3 New requirement

The Princess Elisabeth Zone offshore wind park shall be capable of staying connected to the grid during fast transient high voltages for which the profile of the phase-to-phase voltage versus time in any phase is referred below as High Voltage Fault-Ride-Through (HVFRT). It is recommended however to remain connected as long as the technical capability of the network element would allow.

The proposed Fault-Ride-Through parameters are presented in the Figure 52 below. A voltage U=1 pu represents the rated voltage (phase-to-phase) at the connection point. The same profile applies for asymmetrical faults**.**

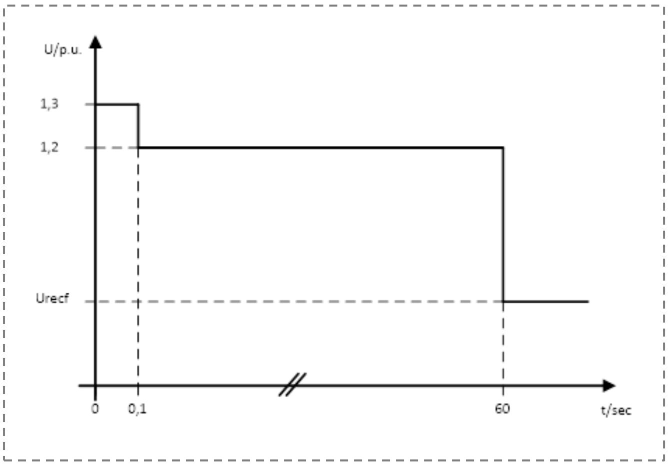


Figure 52 : Profile for High Voltage Fault Ride Through (HVFRT) for PEZ offshore wind park

3.6. Additional requirement for active power forced oscillation

3.6.1. Introduction and context

External phenomena like fluctuations of wind and waves are generating mechanical stress which causes fatigue loads on the wind turbine towers and foundations. This mechanical stress might significantly reduce their lifetime and even lead to wind turbine disconnection if not sufficiently damped.

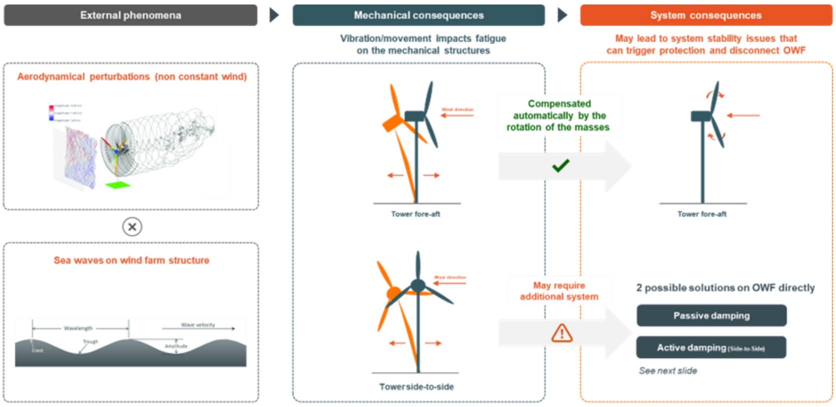


Figure 53 : Forced oscillation phenomena with mechanical and system consequences

Today, 2 possible approaches exist to provide the damping: passive damping or active damping:

1) **Passive damping** is mainly based on structural solution at the level of the wind turbine and does not have any impact on the electrical system, but represents more expensive design for the offshore wind constructor;
2) **Active damping** is a cheaper solution, Side-to-Side Tower Damper (SSTD), that uses electrical torque to reduce the side-to-side tower movements caused by wind and waves fluctuations.

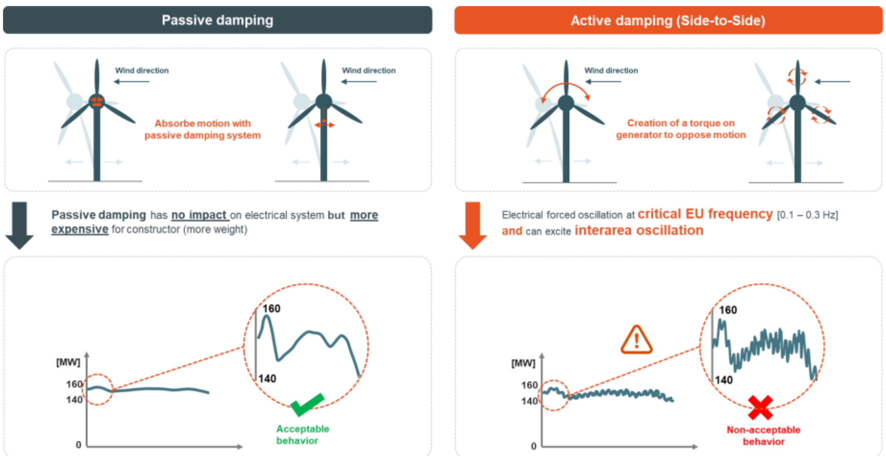


Figure 54 : Mitigation measures for forced oscillation with passive damping vs active damping for offshore wind park and respective impact on electrical system

The torque-based control of the SSTD results in active power variations which causes forced oscillations in the electrical system in the frequency range of [0,1 – 0,3] Hertz. This corresponds to the frequency range where interarea oscillations can also occur in the system, exposing the interconnected transmission system to risk of material damage, frequency or voltage collapse or cascading event resulting in system split up to partial or global black-out.

3.6.2. Current legal references about active power forced oscillation in transmission system

The current version of the European or Belgian grid codes does not make any explicit reference to forced oscillation in transmission system, which led to divergent and opposite interpretation between TSOs and wind turbine manufacturers.

From a TSO perspective, this is interpreted as in the sense that no forced oscillations are authorized in transmission system. From wind turbine manufacturer, this is interpreted in the sense that nothing is preventing them for developing solution which might create forced oscillation. An explicit requirement is providing a more certain way forward for all parties.

3.6.3. Proposal of criteria for active power forced oscillation

In the scope of the amendment process for the Requirements for Generation (RfG) network code initiated by ACER, ENTSOE and Wind Europe, with the support of TSOs and wind turbine manufacturers, have developed a common proposal for criteria defining acceptable forced oscillation in transmission system resulting from the operation of large offshore wind farms. This joint process between TSOs and wind industry at EU level led to a fair compromise and is a significant relaxation with respect to the strict interpretation of the TSOs that no forced oscillations was allowed at all.

Furthermore, the first assessments show that existing Belgian offshore wind farms are broadly compliant, and hence the new farms should be able to reproduce at least similar performance. It is therefore proposed to anticipate the legal process for the amendment of the RfG at EU level and to clarify these criteria for forced oscillation as additional requirements for the PEZ tenders. This provides further certainty for all bidders compared to an absence of explicit requirements.
As the active power forced oscillation shall be monitored at the level of the Access point of the wind park owner, it will allow the OEM of the park to develop strategies to benefit from the aggregation of the individual impact of each wind turbine.

The draft addition related to RfG NC is detailed in the box hereunder. The same requirements will be applied as additional requirements for the PEZ tenders.

Final proposal from ENTSO-E/Wind Europe towards ACER on active power forced oscillations for offshore wind farm in the framework of amendment process for RfG

[Offshore] Proposed addition to RfG NC Article 26 - Robustness requirements applicable to AC-connected offshore power park modules

Outside of the frequency range between 0,1 Hz and 2,0 Hz, the system stability requirement laid down in Article 21.4 shall apply to AC-connected offshore power park modules.

In the frequency range between 0,1 Hz and 2,0 Hz, the control systems and design characteristics of an AC-connected offshore power park modules shall be subject to the following requirements relative to the total active power and current forced oscillations, when system conditions are within the frequency ranges as specified in table 2 and voltage ranges as specified in table 10:

(a) The forced oscillations shall not exceed continuously the maximum of:

(i) a limit in the range of +/- 0,5% to +/- 2% of the actual value, as defined by the relevant TSO. The default limit shall be +/- 1%.

(ii) a limit in the range of +/- 0,25% to +/- 1% of the maximum capacity, as defined by the relevant TSO. The default limit shall be +/- 0,5%.

(b) In case that the limits defined in (a) are temporarily exceeded, forced oscillations shall:

(i) not exceed a limit in the range of +/- 2,5% to +/- 5% of the maximum capacity, as defined by the relevant TSO. The default limit shall be +/- 4%

(ii) be within the limits defined in (a) within a range of 100-180 seconds, as defined by the relevant TSO. The default limit shall be 180 sec.

(iii) be damped to be lower than 50% of the limit specified in (i) within 50% of the time limit specified in (ii).

(c) While always respecting the criteria defined in (b), temporarily exceedance of the limits defined in (a), not considering oscillations that are damped to be within the limits within 10 seconds, is allowed for:

(i) a maximum percentage of time per day, as defined by the relevant TSO in a range between 1% and 2%. The default limit shall be 1%.

(ii) a maximum in a range of 2-4 times per hour, based on the range of the 85th to 95th percentile of hourly exceedances measured over one week, as defined by the relevant TSO. The default maximum shall be 3 times and default percentile shall be 95.

(d) Forced oscillations originated from system support requests by the relevant system operator, such as power oscillation damping, are excluded from this requirement.

3.7. Clarification on resynchronization and island operation needs

3.7.1. Existing requirement

The existing requirements to take part to island operation and quick resynchronization are to be defined on a case-by-case approach as described in art 15.5(b) and 15.5(c) of the EU NC RfG regarding capability.

3.7.2. Reason for modification and expected impact on the design

Considering the characteristics of the units and their prime mover, it is considered not feasible that the units connected to the PEI would take part to island operation (i.e. without external reference of voltage).

The response time after a disconnection is proposed to be 30 minutes. This is considerable acceptable for the technology of offshore wind farms as no complex thermal processes (as in the case of classical synchronous units) are involved in the operation. Hence they shall have the capability to restart within 30 minutes.

The wind park shall be able to detect house load operation not only using the position of the switchgear of Elia but when the external system voltage reference is lost. The above-mentioned specific conditions do not impact the design of the wind park as they are within the current state of the art of offshore wind.

3.7.3. New requirement

The following clarifications are foreseen:

1) The offshore wind park connected to the PEI are not required to take part to island operation;
2) The quick re-synchronization must be such that the offshore wind park can resynchronize and restart production after 30 minutes from the disconnection from the network;
3) The units shall be able to detect house load operation when the system voltage (reference) is lost, and not only using the position of the switchgear of Elia.
4) Taking into consideration the prime mover characteristics, no minimum house load operation time is required.

3.8. Clarification technical requirement for the conformity process

This document presents an improved conformity process applicable to all Power Generation Module (PGM) connecting the Belgian transmission system.

The objective of the improvement of the conformity process is to ensure secure and stable operation of the Belgian transmission system, necessary to limit risk of damage or lifetime reduction of grid user or network installation or severe disruption in the supply of energy, while securing a proportionate, balanced and timely FON delivery process for each new connecting PGM independently from the order they are connecting to the grid. The following subsections discuss:

1) Detailed gap analysis of current and likely future practices and associated challenges.
2) Benchmarking against other jurisdictions with high penetration of IBRs.
3) Guidelines determining the suitable pathway for conformity assessment of each new PGM connection.
4) The proposal for an improved conformity assessment process.
5) The application of this new process to the conformity of the connection of OWFs to the Princess Elisabeth Island.

3.8.1. Detailed gap analysis of current and likely future practices and associated challenges

3.8.1.1 Current state of conformity assessment in Belgium

This section describes the current state of application of conformity assessment for the connection of new Power Generating Modules (PGMs) in the Belgian Transmission System using RMS simulation based Single Machine Infinite Bus (SMIB) approach.
The current conformity process for the connection of a PGM is based on 3 main process parts: EON, ION and FON.

3.8.1.1.1. Compliance process part 1: Elia requirements to deliver the EON

The client needs to perform the following tasks to receive the EON from Elia:

1) Data questionnaire completed and reference simulation models validated
2) PGM internal statement of compliance (RGIE, PCC requirements,…)
3) Statement of compliance delivered by proof/documentation:
    a) Voltage and frequency performance

b) Telecommunication – information exchange
c) balancing (type C only) – ex: power gradients
d) Compliance to power quality requirements (if requested by Elia)
e) Emergency and restoration – reconnection requirements

3.8.1.1.2. Compliance process part 2: Elia requirements to deliver the ION

The client needs to perform the following tasks to receive the ION from Elia:

1) Statement of compliance via simulations and studies for some requirements & delivery of simulations updated models;
2) Presence of a disconnection relay for distributed generators only;
3) Planned test.

3.8.1.1.3. Compliance process part 3: Elia Requirements to deliver the FON

Finally, today, the client needs to perform the following tasks to receive the FON from Elia:

1) Statement of compliance via tests for:
    a) Voltage and frequency performance;
    b) Telecommunication - information exchange;
    c) balancing (type C only) – ex: power gradients;
    d) Power quality tests (if requested by Elia);
    e) Emergency & Restoration.
2) Adaptation of data questionnaire and models previously sent if needed.

All the relevant reference documents describing the requirements to be met, the general principles of the conformity process, including general description of simulation and tests that will need to be performed are provided at the end of the detailed study done by Elia (EDS).

A specific conformity kick-off meeting is then organized by ELIA when the Client has ordered the realization of the project, following which Elia provides detailed check-list and information specific to the connection case (reference voltage, minimum and maximum short-circuit power (Scc) at connection point,…), and Scc to be used to model the grid in the simulations.

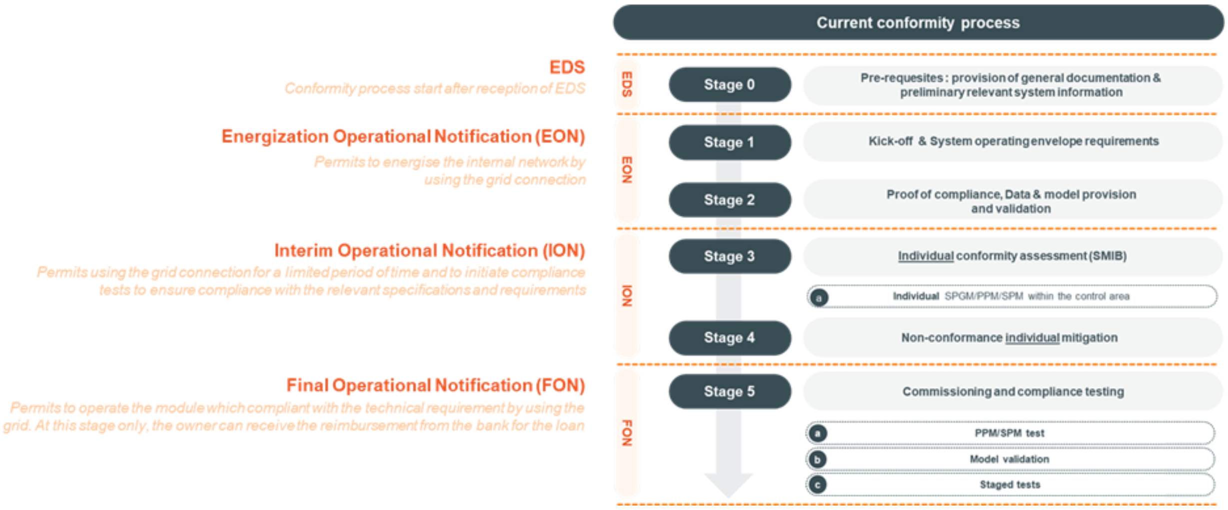


Figure 55 : Current conformity process in Elia for PPM

In order to receive the Interim Operational Notification (ION) that will authorize the unit to be connected to the grid, each new PGM needs to satisfy to a conformity assessment based on the following principles:

1) Currently power system studies for assessing the conformity and performance of the design of each new PGM installation is carried out without accounting for the dynamic response of the existing or future nearby generation and network assets;
2) The wider power system is represented with static data on Min/Max Short Circuit Current (SCC) range at the connection point. The SCC range is generally associated with a certain time in the future at which the PGM is anticipated to connect to Elia's power system;
3) Grid connection studies are fully handled by the connecting party (often via their consultants) using the above simplifying assumptions;
4) Whilst the connecting party might perform studies using the more detailed Electromagnetic Transient Simulation (EMT) simulation to better inform their design, they are only requested to submit study results to Elia with the simpler Root Mean Square (RMS) model in PowerFactory;
5) Once the study report is received from the connecting party, Elia will then assess the connection application in line with RfG general requirements, only based on PowerFactory (RMS) results and without integrating the PGM model into the wider Belgian power system model;
6) Up to 2023, acceptance testing and verification of the dynamic models to ensure sufficient robustness, accuracy and adequacy before their use was not subject to a formal process.

After having received their ION status:

1) Gride Code compliance tests are done following Elia's approval of the RMS studies, conducted by the connecting party. These tests typically comprise the application of small-disturbances such as set-point changes within the PGM installation, or forced system disturbances such as shunt reactor/capacitor activation/deactivation and transformer and line switching. System disturbances are often executed by Elia as they will typically involve the use of the equipment in the wider power system. Results are then plotted and submitted to Elia to demonstrate compliance and to indicate potential performance anomalies and non-compliances that might not have been identified during the modelling stage. After successful application of these tests, the PGM will receive its Final Operational Notification (FON);
2) Ongoing performance of individual generators, and the accuracy of their simulation models is only investigated when there is a major system event or strong indication of actual non-compliances. Again, up to 2023, validating PGM models against staged tests or measured system disturbances is restricted to those facilities providing ancillary services and does not form an integral part of the overall approval process Elia need to grant to all PGM projects.

Figure 56 summarizes the SMIB approach described above. As reminder, this approach is acceptable for connection of synchronous machine or power park modules connected to strong grid, but becomes insufficient to cope with the challenges/trends leading to new power system stability phenomena that the Belgian power system will face.

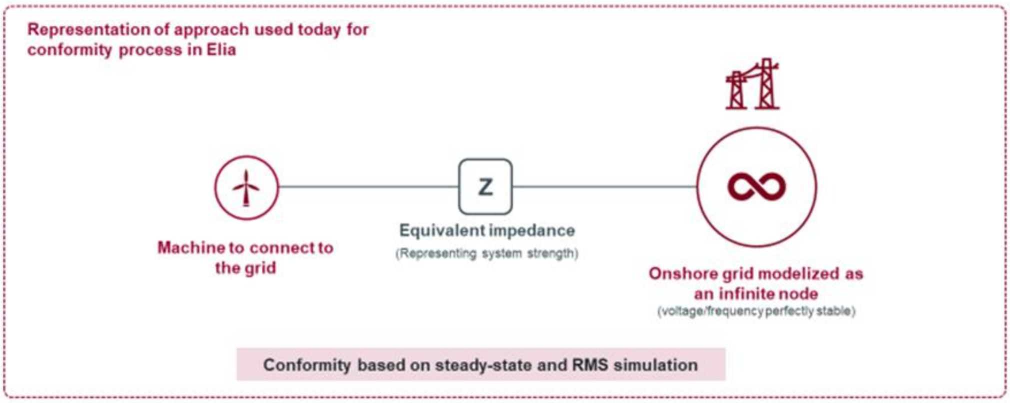


Figure 56 : Current practice for simulation based conformity assessment in Elia

3.8.1.2 Main technical challenges to reach the (ideal) solutions

As already stated, the objective of the improvement of the conformity process is to ensure secure and stable operation of the Belgian transmission system, necessary to limit risk of damage or lifetime reduction of grid user or network installation or severe disruption in the supply of energy, while securing a proportionate, balanced and timely FON delivery process for each new connecting PGM independently from the order they are connecting to the grid.

In this section, we are presenting the main challenges related to the needs and constraints that the proposed improvements will have to address. These challenges are illustrated in the Figure 57.

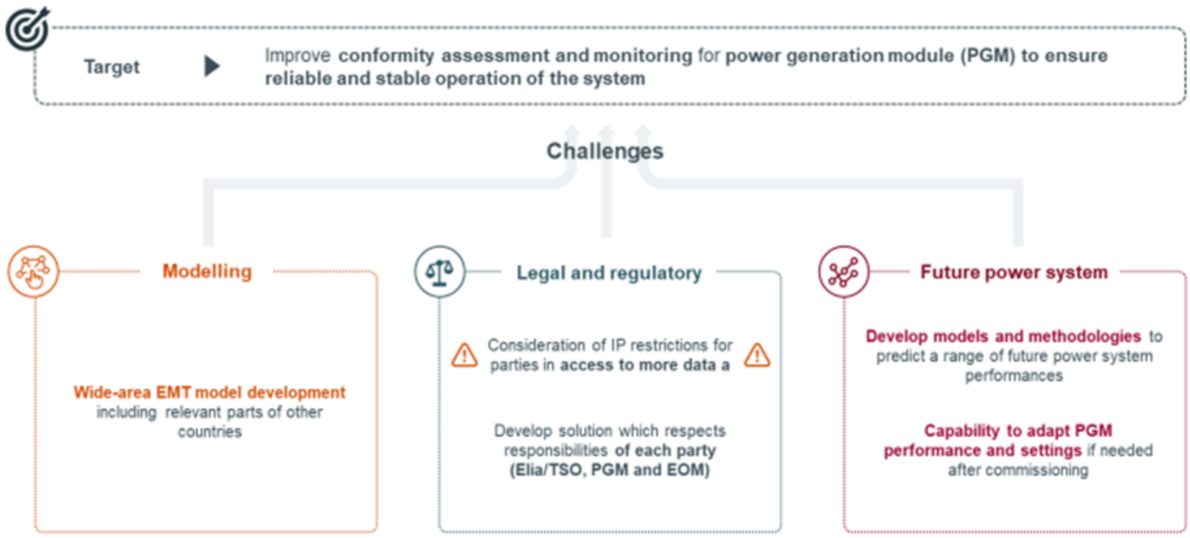


Figure 57 : Categories of challenges to develop an improved conformity assessment process

3.8.1.2.1. The need for more detailed modelling and simulation tools

Worldwide experiences indicate that RMS power system stability analysis tools have often not been able to predict phenomena associated with IBR control system response which is due to the inherent simplifications in these tools. The consequence of this inability to predict the problems during the design of the installation is that problems might be first experienced during actual power system operation, at which point it is more difficult to address and more disruptive and costly to the connecting party, i.e., if the system operator or network owner needs to invoke a constraint to pre-empt the impact on power system stability or nearby network users.

Another approach previously adopted in countries without access to detailed EMT modelling is conservative power system operation, where the power system is purposely operated below its transfer capability to cater for the occurrence of unknowns in the absence of accurate answers based on accurate models. This is an equally inefficient approach and at present impractical to determine with sufficient accuracy.

Detailed wide-area modelling, using EMT tools and representing explicitly most parts of the power system with dynamic models, has therefore been increasingly used in recent times in particular in countries/regions with higher IBR penetration to address the problems discussed above. In Belgian context, this will mean EMT model of sufficient part of Belgian transmission system and possibly a portion of nearby countries. However, noting the significantly meshed nature of Belgian power system and nearby countries, a further challenge arises in determining the boundary of the power system to be chosen for the analysis to allow a trade-off between good accuracy (not missing any plant of significance) and speed (not including power system plant or network without any impact on the dynamic response of the area of interest).

This detailed wide-area modelling will facilitate accurate long-term power system planning allowing the identification and resolution of new and emerging phenomena before they manifest in real power system operation. It will also permit a more accurate, albeit more in-depth, assessment of the impact of connecting new IBRs on power system planning and operation. This detailed modelling will also facilitate better understanding of the performance of emerging technologies such as grid-forming inverters and how they can be best designed to meet emerging power system needs and technical requirements in power systems with significantly higher IBR penetration.

However, detailed wide-area modelling and simulations, especially EMT ones, are more time and resources consuming. This means the improvement of the conformity process will need to address in a proportionate way, depending on the type and size of the PGM, when and how detailed wide-area modelling will be needed.

3.8.1.2.2. Legal and regulatory challenge to use same source of truth for detailed modelling information

Detailed EMT model are usually an one-to-one representation of the actual controls used in the real product. As such Original Equipment Manufacturers (OEMs) are reluctant for that other parties to access their detailed models, and associated control loops and parameters.

Often Elia can only observe a problem caused by multiple IBRs but cannot determine the extent of participation form different plants or the root cause(s). This is because Elia can only receive an encrypted (black-box or grey-box) model.

Elia, or their consultants via an Non Disclosure Agreement (NDA), are the only entities with legal access to the full wide-area model of Belgian power. When only receiving limited and simplified information about the power system around their connection point, the Developers/OEMs may not often be able to anticipate or replicate the problem Elia observes due to the absence of dynamic models for other generators in their studies.

This means that the conformity process needs to be improved in the way to provide Developers/OEMS access to more detailed information of the relevant grid element around the connection point and accurate model in term of its dynamic behavior.

3.8.1.2.3. Challenge on continuously evolving power system and generation during the lifetime of the generation facility

Once their FON is granted, generators will likely have an expectation that they should be protected against future changes in the power system and generation mix, even if they are the key contributors to an instability that did not exist until new generators are included in the overall power system. The Evolution of the system and integration of new assets might have a strong impact on global dynamic performance which cannot be always mitigated by sole adjustment of the dynamic performance of the last comer(s). Moreover, when the observed instabilities require installation of a solution, solution installed in the wider power system could be more optimal and provide benefit to multiple generators.

This means that the conformity process needs to consider the following aspects:

- The conformity process ensuring that any new entrant generators can use the available system strength in a proportionate and balanced way taking into account existing and future concurrent connections;
- the conformity process should not only focus on the expected year of connection of the PGM, but should also account with different combinations of anticipated generator commissioning and retirements/withdrawals expected to occur in other future years reasonably known to Elia with clear role and responsibilities defined for each parties;
- After the FON is granted to the PGMs and during the ongoing lifetime of the PGM installation, ELIA should have possibility to expect from the already connected generators, under reasonable conditions, to adjust their settings and even perhaps control modes to optimize the global system performance.

3.8.2. Benchmarking other jurisdictions with high penetration of IBRs

3.8.2.1 Introduction

Very few countries/regions have already implemented improved solutions. The most similar countries to Belgium such as Denmark and UK are at approximately the same level of reflection than Belgium with regard to the use of EMT modelling for wide-area system stability studies and for developing the necessary solutions.

Experiences gained from two separate large system disturbances in Texas, referred to as Odessa' , has shown modelling and process deficiencies even in regions with long history of wide-area EMT modelling and studies. Australia and to lesser extent France have also been using wide-area EMT modelling, however, these countries are fundamentally different to Belgium, also noting that in France EMT modelling is focused on specific sub-regions .

Whilst Australia is probably at the forefront of the use of EMT modelling for developing the necessary solutions, the number of ongoing initiatives to improve the processes and approaches is a testament of the need for further improvement, and that Australian experience can only be of partial assistance to Elia.

3.8.2.2 TSO knowledge sharing and benchmarking workshop

On 31 March 2023 Elia organized a workshop with other European TSOs to discuss best practices for conformity assessment of large inverter-based resources (IBR) especially for areas with concentration of these devices. The workshop was attended by 50 Hz, Eirgrid, Energinet, Fingrid, TenneT (Netherlands), The National HVDC Centre (UK), and Aurecon (assisting Elia).

As main outcome of this workshop, it was unanimously agreed that ''Process development for assessing and approving the model and performance of new connected PGMs'' has the highest importance for all countries represented. As a starting point, a high-level proposal defining the key distinct stages for assessing and approving PGM conformance has been proposed. A 5 steps process was then developed, with input from participants, as shown below. It was discussed that some of these steps do not currently happen but would be required moving forward with increased penetration of inverter-based resources in close proximity.

1. **System operating envelope requirements**
   This is to set out a range of plausible power system operating conditions for the current power system and moving forward upon which the PGM performance should be assessed. Various scenarios with different generation mix and network operating conditions shall be defined.

2. Model acceptance testing

This is to ensure that models provided are robust and give rise to reasonable performance for the specific site under consideration rather than assessing their compliance with various aspects of technical performance standards.

3. Conformity assessment of the PG

3.1. Conformity assessment of the individual PGM within the TSO jurisdiction

Primarily SMIB studies with both RMS and EMT models, and potentially some wide-area studies but looking at the performance of one PGM only. This step is always needed.

3.2. Collective performance assessment of multiple PGMs within the TSO jurisdiction

Primarily wide-area studies with wide-area RMS and EMT models of the TSO's power system (or sufficient part of it) looking at the performance and interaction between multiple PGMs within TSO's jurisdiction. This step is needed if there are multiple large IBRs nearby.

3.3. Collective performance assessment of multiple PGMs involving other TSO(s) (if needed)

The same as above, however, the wide-area power system models used will include a representation of power systems of two or more TSOs as relevant. This step is not currently possible due to significant modelling efforts and multi-TSO coordination and will be a mid-term goal.

4. Non-conformance mitigation (if needed)

Determining the need and effectiveness of control system tuning, or the installation of synchronous condensers or grid-forming inverters if an instability is identified from the studies conducted in any or all of stage 3-5.

5. Commissioning and compliance testing

5.1. Staged tests (if needed)

This often comprises the application of small disturbances that will be observable by multiple PGMs. The objective is often to assess the collective performance of multiple nearby PGMs. Where possible response to a range of system operating conditions, e.g., high and low system strength, is assessed.

5.2. Model validation

Validation of the model received.

3.8.3. Guidelines suitable pathway for conformity assessment

The outcome of the activities highlighted in Chapter 3 including the knowledge sharing and benchmarking workshop with other TSOs has allowed Elia to further think and mature its enhanced conformity assessment process and various stages involved.

The objective Elia has followed when defining the improvements of the conformity process necessary to cover the challenges, constraints and needs presented in the previous chapters was to ensure secure and stable operation of the Belgian transmission system, necessary to limit risk of damage or life time reduction of grid user or network installation or severe disruption in the supply of energy, while securing a proportionate, balanced and timely FON delivery process for each new connecting PGM independently from the order they are connecting to the grid.

Some further investigations and analysis, with adequate justification in case several options where identified, have been done in order to detail the actions, criteria, role and responsibilities to be considered in each stage, especially for topics which are new or slightly different from current practice.

3.8.4. Criteria for individual or collective conformity assessment

As already explained, in order to ensure secure and stable operation of the Belgian transmission system, necessary to limit risk of damage or lifetime reduction of grid user or network installation or severe disruption in the supply of energy, it is of upmost importance to correctly assess the risk of new stability phenomena arising in case of concentration of large IBRs or HVDCs. The assessment of these phenomena cannot be obtained via only SMIB RMS based simulation and require wide-area network-based simulations. This section presents the criteria to decide on the need for individual SMIB based or collective wide-area based conformity assessment as shown in Figure 58.

Four types of assessments are envisaged depending on the criteria met:

1) SMIB RMS based assessment;
2) SMIB EMT based assessment;
3) Wide Area RMS based assessment;
4) Wide Area EMT based assessment.

It is noted that these criteria have been developed with a view on the future evolution of Belgian and interconnected EU power systems in mind where more and more IBRs are expected to be connected. Moreover, the criteria have been defined and quantified in order to deviate as less as possible from the current conformity practice and remaining proportionate to the impact on the risk for secure and stable operation of the Belgian system that the size and concentration of connected IBRs might represent.

The following criteria are considered for the determination which kind of simulations a new PGM shall undergo in order to prove conformity:

1) SPGM/PPM/SPM type: Type A, B , C and D SPGM, PPM and storage as defined in the Belgian regulation;

2) SPGM/PPM/SPM size: the 1MW, 25MW and 75MW threshold, already applicable for the Type of PGMs will be considered;

3) An aggregate SCR index: Index aiming at screening the risk that close-by PGMs, synchronous condensers or HVDC might affect stability performance of the power system and will require wide-area network simulation to be assessed. The screening index is based on a list of relevant assets identified based on their relative size and relative electrical distance. The screening index is expressed as follow:

$$\frac{\mathrm{Scc_i}}{\left[\mathrm{Snom_i} + \sum_j \mathrm{MIIF_{ij}} * \mathrm{Snom_j}\right]}$$

Where

- Snomi: Nominal Apparent Power of Assessed SPM/PPM;
- Scci: Minimum short circuit power at connection node of Assessed PPM/SPM;
- Snomj: Nominal Apparent Power of Relevant Assets;
- MIIFij: Voltage dip on connection node of relevant PPM/SPM j in case of 3-phase metallic short circuit on connection node of Assessed SPM/PPM as a representation of the relative electrical distance between the assets.

And where the determination of the Relevant Assets is based on:

a) SPGM/Synchronous condensers where Scc, spgm, I >= 10% Scci with Scc, spgm = Scc contribution of relevant SPGM to Scci;

b) HVDC/PPM/SPM where MIIFij*Snomj > 10% Snomi AND MIIFij > 10%.

Based on these criteria, the following conclusions were drawn:

1) No simulations are required for Type A PGMs.
2) All Type B, C and D PGMs shall be requested to perform individual conformity assessment via SMIB RMS based simulations
3) All Type C and D SPM/PPM shall be requested to perform individual conformity assessment via SMIB RMS and EMT simulations.
4) All Type C and D SPM/PPM with a size above or equal to 75MW and in a situation where the aggregate SCR is below 3 shall be requested to perform a collective conformity assessment via Wide Area RMS and EMT based simulations.

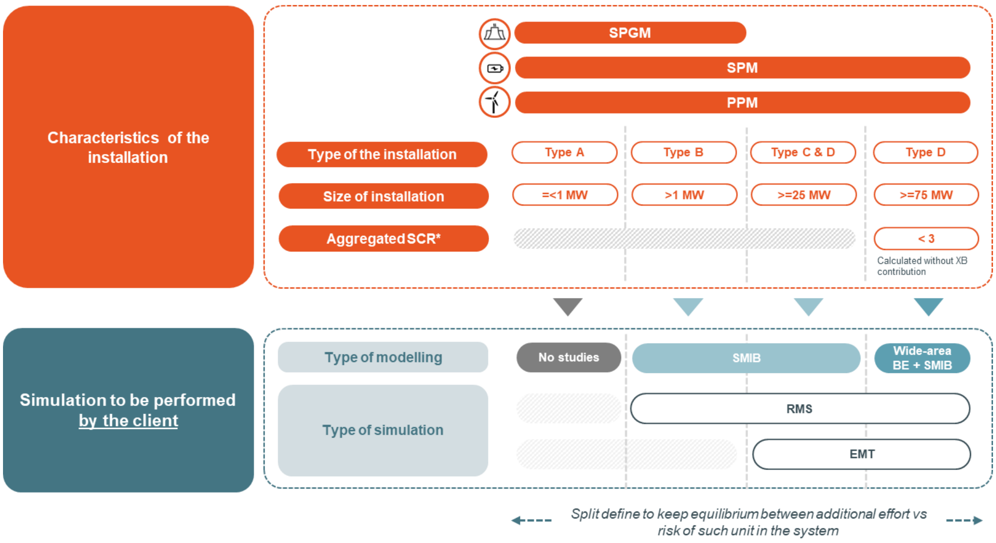


Figure 58 : Criteria to decide on individual or collective conformity assessment for PPMs/SPMs

These criteria and results shall be first applied by Elia during the EDS phase, and then they shall be communicated to the client as information part of the stage 0: prerequisites for the conformity process. A re-assessment and formal definition shall then be applied by Elia during the stage 1 of the conformity process aiming at defining the System operating envelop.

3.8.5. Modelling of the SMIB network for individual assessment

In all cases where conformity requires simulation-based assessment, an individual assessment of the requirements' performance of the installation shall be performed on a SMIB network model, as it is already currently the case.

In case no relevant asset has been identified, the SMIB model shall be composed of an infinite bus connected to the grid behind an equivalent impedance computed based on the Sccmin and Sccmax at the connection point of the installation.

In case relevant assets have been identified, justifying a collective assessment on top of the individual one, these relevant generations shall be considered in the following way in the SMIB network model for the individual assessment:

1) In case of similar type of generations connected on the same node, those generation shall be explicitly modelled using sized identical model of the installation of the under conformity assessment;
2) In case of different types of generation connected to the same node or in case of different connection node, their impact shall be considered in the in the value of the equivalent impedance. The equivalent impedance shall be computed has being the inverse of the Aggregate SCR used for the definition of the individual or collective assessment.

3.8.6. Data, model and information to be exchanged between Elia and the Client

On top of the usual proofs of evidence that the Client shall provide during the EON phase, the Client shall also provide to Elia data and model of its installation allowing representative RMS and EMT simulations. The details of these data and model to be provided and the process to validate or update this information during the conformity process are described in Section 3.9.

In the other way round, Elia shall provide following information, data and model allowing the Client and OEMs to better estimate the effort and perform the required simulations ensuring an optimal design of performance of its installation accounting for the characteristic of the surrounding grid:

1) A document with the list of requirements applicable to offshore OWFs and the way conformity will need to be proven in the EON, ION and FON parts;
2) Minimum and maximum Short-circuit power at the connection point;
3) When applicable, anonymized list of Relevant HVDC/PPM/SPM assets as identified for the collective assessment determination with their Snom and MIIFij characteristics;
4) When applicable, anonymized list of Relevant SPGM/Synchronous condensers with their contribution to the Short-circuit power at the connection point;
5) Minimum and maximum Aggregate SCR;
6) Rough estimation of number of scenarios and events to be simulated in RMS and EMT in wide area and rough estimation of simulation time;
7) SMIB model in Power Factory and PSCAD and access to the Wide Area Network model.

3.8.7. Performance of collective assessment based on wide-area network EMT model access

The performance of wide-area network based simulations will require for Elia to develop and put at Client's disposal a RMS and an EMT network model representing in detail the grid elements and relevant assets that are necessary to accurately simulate the dynamic performance of the power system.
As such network models contain data and models from relevant asset which are subject to strong confidentiality clause and cannot be freely shared by Elia to third parties.A solution has to be found to allow the Clients to still perform the wide-area network simulations necessary to optimize its performance and validate its compliance with Elia requirements.

Elia has investigated 4 options on the way to perform the collective assessment (see Figure 59):

(1) **Option 1:** PPM/SPM owner will have direct access to wide-area RMS and EMT models;
(2) **Option 2:** An independent organization with legal access to the wide-area RMS and EMT models will perform the simulation;
(3) **Option 3**: PPM/SPM owner will have indirect access to wide-area RMS and EMT models via a cloud-based platform;
(4) **Option 4:** Elia will conduct the studies by itself and advise the PPM/SPM owner of the outcome.

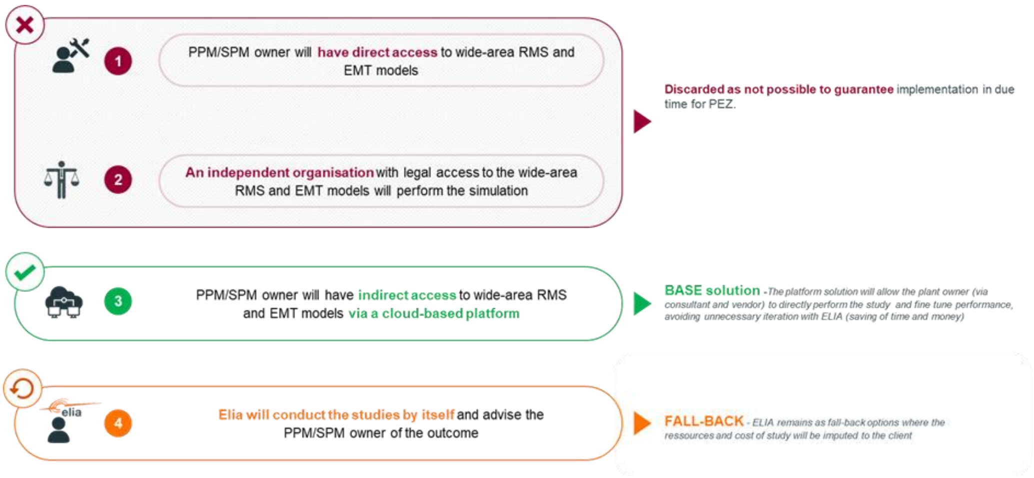


Figure 59 : Different options on the way to perform the collective assessment

Out of the 4 options, options 1 and 2 have been discarded from further detailed analysis as their feasibility and implementation time are subject to conditions which are not fully in Elia hands and not guaranteed to be compatible with PEZ timings. These options will be kept for potential longer-term solution. Focus has been then put on option 3 and 4.

Based on a pros/cons analysis and based on the current return of experience of similar application in Australia, Elia is proposing to prioritize the implementation of option 3. Option 2 is still considered as a fallback solution in case and only if the client would not be able to perform assessment via the option 3 due to a reason independent from his responsibility.

In the case collective assessment will be done by Elia itself, Elia shall have the right to be supported by an external consultant. Both Elia and this consultant shall need to get access to the detailed RMS and EMT model of the installation of the client via adequate NDA when necessary. The Client shall bear the costs of the study.

3.8.8. Envelop of scenarios and operating conditions for simulation

For each requirement subject to simulation proof, Elia shall determine the envelop of operating conditions and events that will have to be simulated in order to sufficiently cover the identification of potential system stability risks and in which model (SMIB RMS, SMIB EMT, wide-are network RMS, Wide-area network EMT). The envelop of operating conditions shall be minimized to keep the simulation effort as low as possible.

The following operating conditions shall be considered for the simulations:

- Maximum and minimum Active Power injection;
- Maximum and minimum strength of the AC power system;
- When applicable, different potential connection topologies to the AC Belgian power system: AC connection, DC connection or parallel AC/DC connection.

The following type of events shall be simulated:

- 1-phase or 3-phase short-circuit on close-by substation(s) eliminated by clearing of the faulty busbar after 200ms;
- Disconnection or change of setpoint of close-by Relevant Assets.

These operating conditions and events shall be assessed for 2 time horizon:

- Expected time of connection;
- Target time horizon = 5 years after expected time of connection in order to get awareness of potential risk of unsecure or unstable operation and already take it into account in the design and tuning of the dynamic performance of the installation.

3.8.8.1 Non-conformance mitigation

In case of non-conformance, the following principles shall be used to address mitigation solution:

► **If the non-conformance is observed during the individual assessment**

The client shall remain sole responsible to find mitigation and shall have an obligation of result.

► **If the non-conformance is observed during the collective assessment**

(1) Elia, with potential support of external consultant, shall coordinate the mitigation assessment.

(2) The relevant generations considered in the collective assessment shall be categorized as follow:

(a) **Assessed:** Network/generation assets undergoing conformity assessment;

(b) **Future**: generation/network assets with known connection point and size, conformity on-going or expected in the next 5 years but conformity assessment has not yet started and performance has not been approved;

(c) **Committed**: generation/network assets whose performance is approved and connected < 5 years;

(d) **Existing**: generation/network assets already connected for more than 5 years.

(3) The following principles shall be respected for the mitigation role and responsibilities:

(a) The Asset Owner shall have an obligation of result in term of full compliance for the Expected connection time horizon and shall have an obligation of means to monitor and solve potential non-conformity for the Target time horizon, without causing a disproportionate investments. During the assessment for the Target time horizon, if monitored instabilities involved Future asset(s) and cannot be reasonably solved by the Assessed asset, solutions will be further investigated during the conformity assessment of the Future asset;

(b) In all cases solution will be first looked at the level of Assessed asset;

(c) Retuning of Elia asset shall be considered at same level as solution on generation;

(d) If required by Elia, Committed assets have obligation of means to investigate and implement possible solution within their installation. Full responsibility and cost shall be beard by the asset Owner under the following conditions:

(i) Elia might request investigating solution within period of max 5 years following the reception of their FON status;

(ii) Elia might introduce a maximum of 5 requests;

(iii) Investigated solution shall be limited to retuning of control command performance while respecting the hard limits of the installation;

(iv) The Asset owner shall keep its FON status if delivered;

(v) In case the Asset owner is requested to analyze a possible retuning, time for the analysis shall be agreed with the TSO;

(vi) In case the Asset owner is requested to implement a solution, implementation time shall be agreed with the TSO. The agreements of the Asset owner shall not be unreasonably withheld, and a disagreement shall always be thoroughly justified on the basis of the negative impact that such implementation would have on its assets;

(vii) If a solution would concern an Existing asset, its implementation shall be assessed on a case by case basis

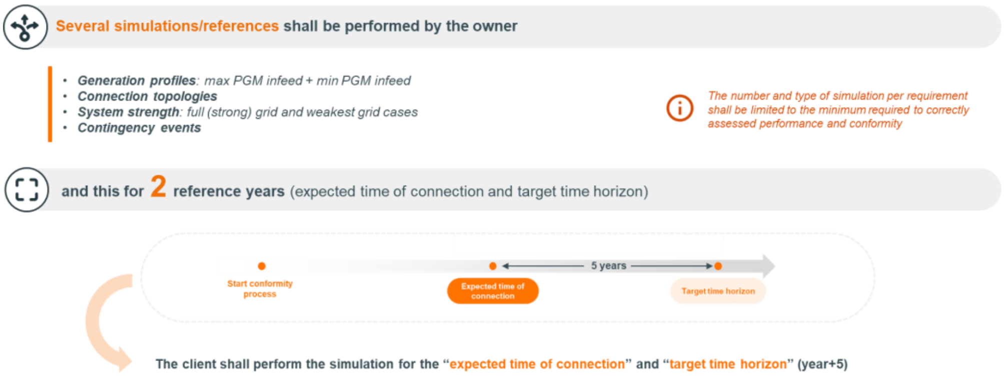


Figure 60 : Scenarios and reference years for conformity process

3.8.8.2 Proposal for improved conformity assessment process

In this section, the updated Conformity Process with the different activities, role & responsibilities of each party to be considered in each Stage of the process is presented.

Figure 61 presents a comparison of the proposed five-stage process against the EU-level legally binding stages of energization operational notice (EON), interim operational notice (ION) and final operational notice (FON). As shown the proposed process is consistent with the existing framework providing more details on the activities required and roles and responsibilities of parties involved.

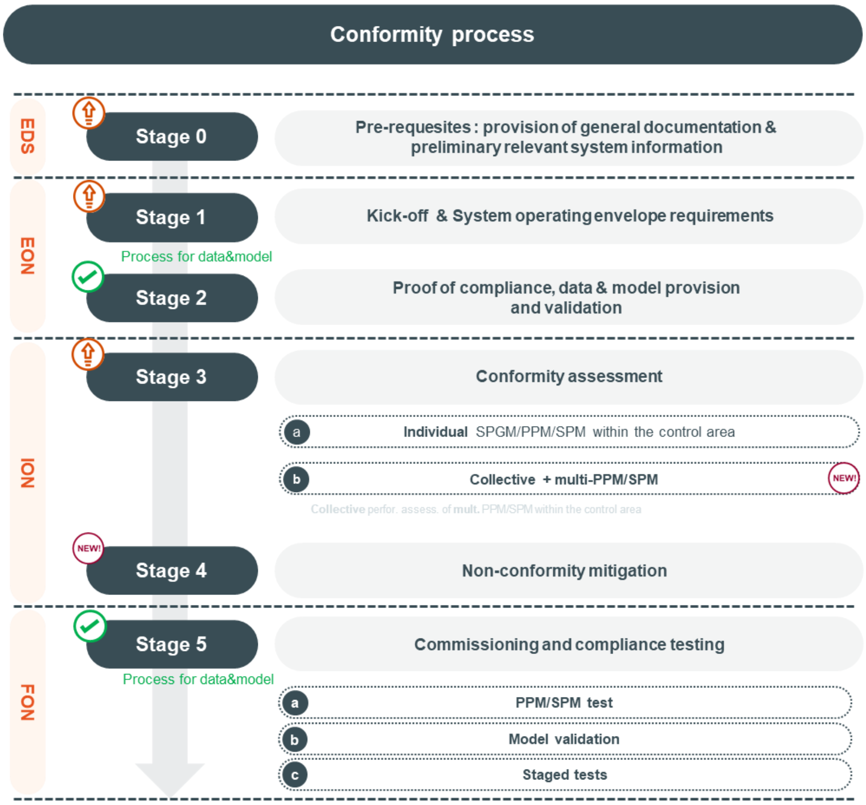


Figure 61 : Comparison of the proposed five-stage process against the EU level EON, ION, FON stages

Stage 0: Pre-requisites

As input provided at the end of the EDS, TSO shall provide the client with:

- **List of applicable requirements that will be subject to the conformity assessment.**
- **Conformity Process description, criteria**: Description of the conformity steps that the PGM will need to undergo depending on individual SMIB based assessment or collective wide area based assessment.

- **Data and Modelling provision and validation process and criteria** to be considered in the conformity assessment process for PGMs accounting for their size and proximity to other nearby plants. These criteria include, but not limited to:
  - *RMS and EMT models of the proposed PPM/SPM;*
  - *Model certification, lab tests, hardware-in-the-loop or other forms of evidence, as agreed between Elia and PPM/SPM owner, to provide confidence in model reliability and accuracy;*
  - *Benchmarking between the RMS and EMT models;*
  - *Parameters mapping sheet between the RMS and EMT models.*

  These criteria and related process is defined in Section 3.9.
- **General template** for compliance follow-up to be completed by the PGM owner for each connection
- **The Relevant information applicable to the PGM** connection case:
  1. *Minimum and maximum Short-circuit power at the connection point*
  2. *When applicable, anonymized list of Relevant HVDC/PPM/SPM assets as identified for the collective assessment determination with their Snom and MIIFij characteristics*
  3. *When applicable, anonymized list of Relevant SPGM/Synchronous condensers with their contribution to the Short-circuit power at the connection point*
  4. *Minimum and maximum Aggregate SCR*
  5. *Rough estimation of number of scenarii and events to be simulated in RMS and EMT in wide area and rough estimation of simulation time*

Stage 1: Kick-off and System operating envelope requirements

► Stage 1-1: TSO

The TSO shall invite the PGM owner to a kick-off meeting when the realization of the project has been ordered. The TSO shall provide to the PGM owner:

1) Update of the Relevant information applicable to the PGM connection case
   (a) *Minimum and maximum Short-circuit power at the connection point;*
   (b) *When applicable, anonymized list of Relevant HVDC/PPM/SPM assets as identified for the collective assessment determination with their Snom and MIIFij characteristics;*
   (c) *When applicable, anonymized list of Relevant SPGM/Synchronous condensers with their contribution to the Short-circuit power at the connection point;*
   (d) *Minimum and maximum Aggregate SCR.*
2) SMIB model in Power Factory and PSCAD and access to the Wide Area Network model;
3) Detailed list of operating conditions scenario and events to be simulated in RMS and/or in EMT in the different SMIB and Wide Area network models for both expected time of connection and Target time horizon. The information to be provided includes:
   (a) *A list of critical contingencies;*

(b) The dispatch of synchronous generators and inverter-based resources;

(c) Import and export levels from the AC and DC interconnectors;

(d) Strong and weak grid condition.

► Stage 1-2: PGM owner

The PGM owner shall test the access to the Wide Area network models.

Stage 2: Proof of compliance, model & data provision and validation

► Stage 2-1: PGM owner

The PGM owner shall:

- Provide the proof of evidence for the different concerned requirement as listed in the EON part of the general template for compliance follow-up;
- Submit vendor-specific RMS and EMT models of the PGM and supporting documentation as required in the Section 3.

► Stage 2-2: TSO

The TSO shall:

- Review the submission from PPM/SPM owner and provide conditional approval to use the models submitted for the conformity assessment;
- If models cannot be accepted at this stage, provide feedback on what needs to be improved and re-submitted;
- Validate proof of evidence and data&models provided by PGM owner so that the PGM owner can be progressed to the next stage.

Stage 3: Conformity assessment

► Stage 3A: Conformity assessment of the individual PGM

► *Stage 3A-1: PGM owner*

The PGM owner shall:

- Undertake SMIB studies with both RMS and EMT models;
- Model Relevant Asset of same Type and same Energy source connected to the same electrical node using identical model but adjusted to their nominal power model;
  - Without dynamic modelling of other nearby PGMs;
  - The network being modelled as a infinite voltage source behind by equivalent impedance;
  - Note that each conformity assessment will only involve one PGM owner, i.e., no coordinated assessment at this stage;
- Determine any non-conformances and pre-emptively address to the extent practically possible with control system tuning.

► *Stage 3A-2: TSO*

The TSO shall review and perform a due diligence confirming one of the following outcomes:

- PGM is compliant at this stage and can proceed to stage 3B;
- PGM exhibits minor non-compliances, however, it can proceed to stage 3B with a view to determine more efficient system-wide solutions after understanding the potential interaction with other PGM(s);
- PGM non-compliances are unacceptable and must be resolved by proposing solutions solely funded by the PGM.

► **Stage 3B: Collective performance assessment of multiple PGMs**

► *Stage 3B-1: PPM/SPM owner*

The PPM/SPM owner shall:

- Access to the ELIA “cloud-based” platform and connect the model of its installation to undertake Wide Area Network studies with both RMS and EMT models;
- Determine any potential non-conformances;
- Resolve non-conformances that can be practically addressed by control system tuning.

► *Stage 3B-2: TSO*

Review and perform a due diligence confirming one of the following outcomes:

- PGM is compliant at this stage and can receive their ION status and proceed to stage 5;
- PGM still faces non-compliances that cannot be resolved by solutions solely funded by the PGM and need to proceed with stage 4.

Stage 4: Non-conformance mitigation

► **Stage 4-1: TSO**

The TSO shall:

- Coordinate and lead the modelling and studies required;
- Determine roles and responsibilities between different Relevant Asset Owner and Elia respecting the following principles:
  a. The Asset Owner shall have an obligation of result in term of full compliance for the Expected connection time horizon and shall have an obligation of means to monitor and solve without causing a disproportionate investments potential non-conformity for the Target time horizon. During the assessment for the Target time horizon, if monitored instabilities involved Future asset(s) and cannot be reasonably solved by the Assessed asset, solutions will be further investigated during the conformity assessment of the Future asset
  b. In all cases solution will be first looked at the level of Assessed asset
  c. Retuning of Elia asset shall be considered at same level as solution on generation

d. If required by Elia, Committed assets have obligation of means to investigate and implement possible solution within their installation. Full responsibility and cost shall be beard by the asset Owner under the following conditions:
    i. *Elia might request investigating solution within period of max 5 years following the reception of their FON status;*
    ii. *Elia might introduce a maximum of 5 requests;*
    iii. *Investigated solution shall be limited to retuning of control command performance while respecting the hard limits of the installation;*
    iv. *The Asset owner shall keep its FON status if delivered;*
    v. *In case the Asset owner is requested to analyze a possible retuning, time for the analysis shall be agreed with the TSO;*
    vi. *In case the Asset owner is requested to implement a solution, implementation time shall be agreed with the TSO. The agreements of the Asset owner shall not be unreasonably withheld, and a disagreement shall always be thoroughly justified on the basis of the negative impact that such implementation would have on its assets*

e. If a solution would concern an Existing asset, its implementation shall be assessed on a case by case basis

- Coordinated control system tuning of nearby Relevant PGMs/Assets;
- If there are residual issues, investigate solution with Assessed PGM, Committed and, on case by case basis when relevant, with Existing Assets.

► Stage 4-2: PGM and Relevant Assessed and Committed Asset owners

PGM and Relevant Assessed and Committed Asset owners shall:

- Participate in the studies in coordination with TSO;
- Address the non-conformances by improving dynamic performance of their installation.

Stage 5: Commissioning and model validation

► Stage 5A: Commissioning and compliance testing

► Stage 5A-1: TSO

The TSO shall propose a compliance testing procedure ensuring:

- Sufficient evidence can be gathered to allow demonstrating compliance with various aspects of the performance (except fault related aspects);
- No adverse impact on system stability (ideally by performing simulation studies);
- Advise specific conditions for which the testing must/not be conducted.

► Stage 5A-2: PGM owner

The PGM owner shall:

- Install the required quantity and quality of high-speed measurement systems within the PPM/SPM;
- Conduct the tests;
- Compare measured and simulated response of the PPM/SPM;
- Identify response aspect(s) where a good correlation between the measurement and simulation was not obtained, discuss the reason and propose a plan to address these during the model validation stage.

► *Stage 5A-3: TSO*

The TSO shall:
- Closely monitor the test in coordination with the control center operators;
- Have the necessary means in place to abort the tests immediately if unstable responses are observed;
- Advise PGM owner of any model or performance improvement needs.

► Stage 5B: Model validation

► *Stage 5B-1: PGM owner*

The PGM owner shall:
- Validate and improve the models based on measurements obtained from stages 7 and 8;
- Determine the need for conducting further tests, especially those involving the wider network and discuss with the connecting TSO;
- Assess the impact of model parameter changes on PGM's ability to meet already agreed performances and advise the TSO if any uncertainties.

► *Stage 5B-2: TSO*

The TSO shall review and advise the PGM owner:

- If models can be accepted as final validated models;
- If further parameter tuning is required before the models can be accepted as final validated models;
- If additional tests are necessary before models can be accepted.

► *Stage 5B-3: PGM owner*

The PGM owner shall eliver final compliance test report and data & model of installation.

► *Stage 5B-4: TSO*

The TSO shall issue the FON

► Stage 5C: Staged tests

► *Stage 5C-1: TSO*

The TSO shall:

- Assess if further compliance or model validation evidences should be obtained by applying stage tests. These tests are often in the form of line or reactive plant switching;
- Perform simulation studies to ensure that those tests will not adversely impact system stability;
- Ensure correct quantity and quality of high-speed measurement systems are installed in the network.

► ***Stage 5C-2: PGM owner***

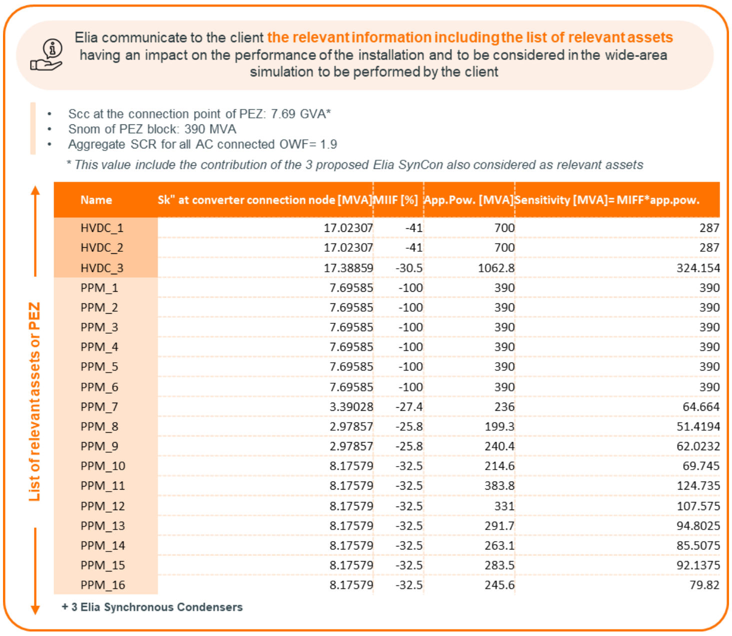
The PGM owner shall ensure high-speed measurement systems are operational and can capture the data during the tests.

3.8.9. Application to offshore wind farm to be connected to PEI

In this section, the improved conformity process will apply for the PEZ offshore wind farms case is described. As there is no EDS process in the context of PEZ, the stage 0 of the conformity process shall be understood to be provided as input for the tender. Each PEZ offshore wind farm shall have a size 350 MW and shall be connected the Elia transmission system on 66kV substation based on fully converter driven solution. According to the criteria defined in the Belgian grid code, each PEZ offshore wind park shall be Type D PPM.

The conformity assessment shall apply at the Access point of the wind park, meaning that the performance shall sum up and aggregate the behaviour of all wind turbines of all streams which belong to the Access point.

Following the criteria and formulas defined in 3.8.4 Criteria for individual or collective conformity assessment, Elia has performed a preliminary assessment of the list of relevant assets (see Figure 62) and has calculated an Aggregate SCR of about 1.9 .



- Scc at the connection point of PEZ: 7.69 GVA*
- Snom of PEZ block: 390 MVA
- Aggregate SCR for all AC connected OWF= 1.9

* This value include the contribution of the 3 proposed Elia SynCon also considered as relevant assets

Name	Sk" at converter connection node [MVA]	MIIF [%]	App.Pow. [MVA]	Sensitivity [MVA]= MIFF*app.pow.
HVDC_1	17.02307	-41	700	287
HVDC_2	17.02307	-41	700	287
HVDC_3	17.38859	-30.5	1062.8	324.154
PPM_1	7.69585	-100	390	390
PPM_2	7.69585	-100	390	390
PPM_3	7.69585	-100	390	390
PPM_4	7.69585	-100	390	390
PPM_5	7.69585	-100	390	390
PPM_6	7.69585	-100	390	390
PPM_7	3.39028	-27.4	236	64.664
PPM_8	2.97857	-25.8	199.3	51.4194
PPM_9	2.97857	-25.8	240.4	62.0232
PPM_10	8.17579	-32.5	214.6	69.745
PPM_11	8.17579	-32.5	383.8	124.735
PPM_12	8.17579	-32.5	331	107.575
PPM_13	8.17579	-32.5	291.7	94.8025
PPM_14	8.17579	-32.5	263.1	85.5075
PPM_15	8.17579	-32.5	283.5	92.1375
PPM_16	8.17579	-32.5	245.6	79.82

+ 3 Elia Synchronous Condensers

Figure 62 : List of relevant assets for PEZ phase 1 conformity process

As illustrated in Figure 63 below, this leads to the conclusion that each PEZ offshore wind farm shall have to apply for a collective conformity assessment based on RMS and EMT simulations realized in both SMIB and Wide-area network models.

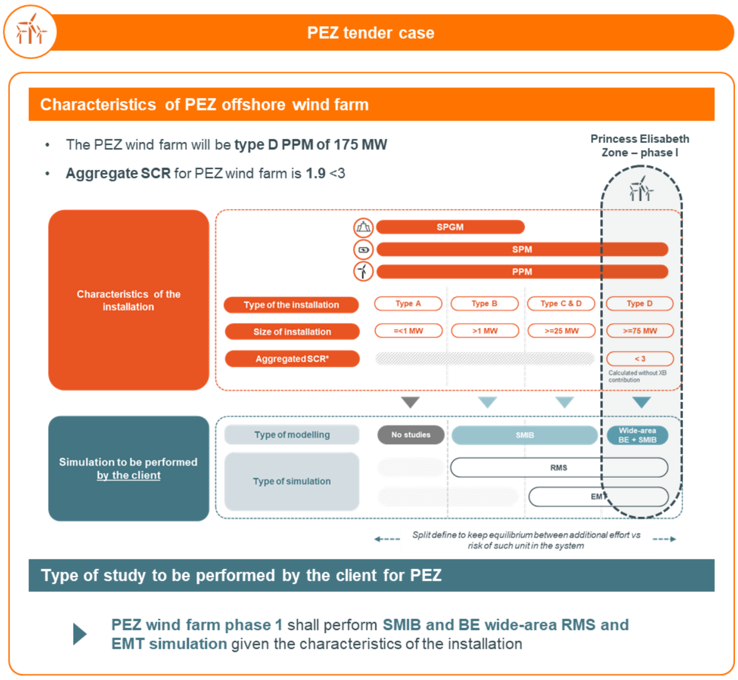


Figure 63 : Characteristics of PEZ phase 1 and simulations to be required in the conformity process

The list of requirements is based on TYPE D PPM requirements defined in the European RfG Network code and the Belgian “General Requirement for Generators” grid code, completed with the additions and improvements detailed in Section 3.3.

The general template for compliance follow-up also refers to the article in the Belgian grid code and the chapter in the Elia document describing the Requirements for general application to PGMs, and highlights whether the conformity should be based on proof of evidence, simulation and/or test.

In this template, Elia has also provided a first rough estimation of the number of simulations per type of simulation environment (RMS/EMT simulations on SMIB or wide-area network models) that will need to be done per requirement. As illustrated in the following picture, a total of about 90 simulations is expected.

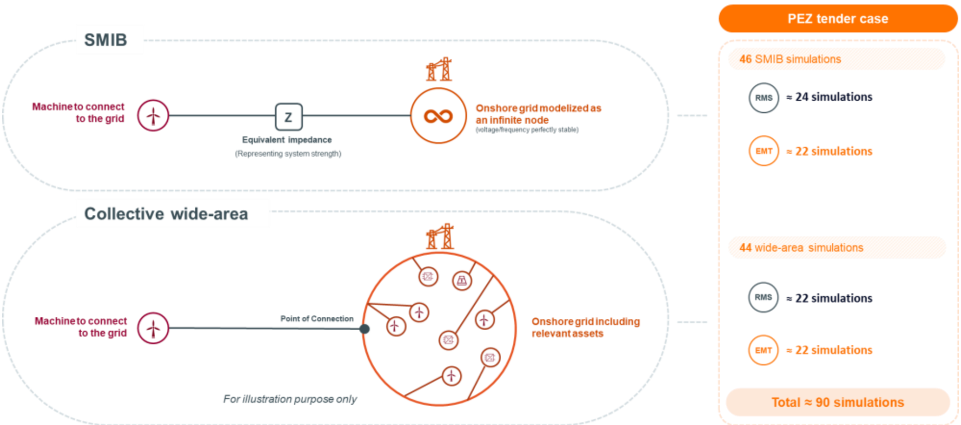


Figure 64 : Number of EMT and RMS simulations in SMIB and wide-area to be performed by the client in the framework of the PEZ tender phase 1

As illustrated in the Figure 65 below, the simulations will cover 2 time horizons: Expected connection time horizon and a Target time horizon being 5 years after having received FON. The relevant assets identified in Figure 62 above will be classify in 4 categories : Assessed, Committed, Future and Existing following the definition presented in Section 3.8.8.1.

During its conformity assessment, to receive its ION and FON, the PEZ offshore wind park owner will have an obligation of result in term of compliance to the requirements for the Expected connection time horizon and an obligation of means for the Target time horizon. By obligation of means, it is meant that the PEZ offshore wind park owner will have to perform the simulations, identify any non-compliance and mitigate at best the observed non-compliance with optimization of the tuning of the settings and parameters of the different controls available in its installation. In the case a non-compliance is also impacted by another Assessed or a Committed Asset, Elia shall coordinate the investigation of solution among these Assets, together with potential solution coming from relevant Asset owned by Elia.

Also, during a period of 5 years following the receival of his FON, the PEZ offshore wind park owner will have an obligation of means, in case of Elia request, to investigate the possibility to modify the dynamic performance of its installation by modifying the tuning of the settings and parameters of the different controls available in its installation, within the dimensioning limit of the installation and without impacting the life time of the installation that might contribute to solve potential system performance issue coming from the evolution of the system or the connection of another relevant close-by asset. In case a solution is found and agreed by each party, the PEZ offshore park owner might be requested to implement the solution in a commonly agreed timing. The agreement of the PEZ offshore park owner shall not be unreasonably withheld, and a disagreement shall always be thoroughly justified on the basis of the negative impact that such implementation would have on its assets. As long as the above-mentioned obligations of means are respected by the PEZ offshore wind park owner, he will keep its FON status for its installation if received.

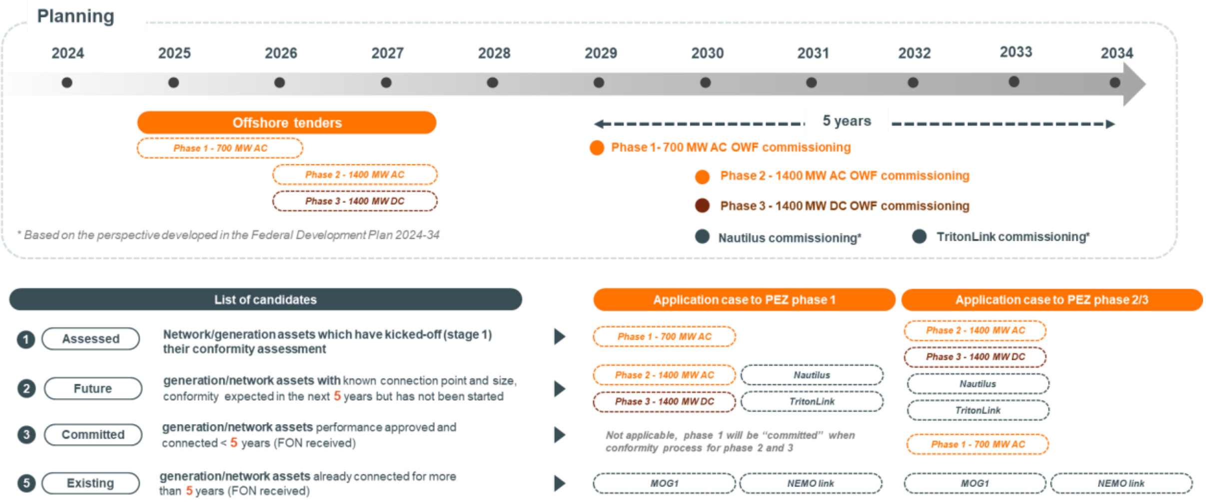


Figure 65 : Candidates in case of non-conformance for PEZ phase 1 and phase 2 & 3

3.9. Clarification of the data and model validation

In line with the Article 15 of the directives Commission Regulation (EU) 2016/631 and the Article 21 of Commission Regulation (EU) 2016/1388, establishing obligations for generation and transmission-connected demand facilities to provide data and model to the relevant transmission system operator (Elia). Elia have established a set of document aiming at clarifying in transparent way the data and simulation needs in term of accuracy and detail. Such models should represent the behavior of power-generating modules in both steady-state and dynamic simulations (50 Hz component), as well as in electromagnetic transient simulations.

Therefore, it is important to mention that this section comes as a clarification on existing Data and Model validation as per the processes and requirements that are already put in place in Elia and would be therefore applicable to new offshore wind generation.

3.9.1. Context and Background

Given these evolution of the power system stability phenomena (see Section 3.2.), it becomes essential to improve the processes, methodologies and simulation models quality in general. Elia already investigated improvements to the existing provisions based on international benchmarking for advanced systems facing similar technical challenges. The processes put in place to cover the following key elements:

1. **Simulation Model Requirements**: The focus here is on ensuring that the models and the data are accurate and suitable for system studies that need to be conducted by Elia.
2. **Model Validation Procedure**: This process aims to enhance the representation of the new phenomena and to conduct stability studies with precision. Such process lay done the requirements and the key steps that need to be addressed throughout the connection process.

3.9.2. Processes Description

1. Simulation Model requirements

To enhance the expectations in of simulation model requirements, two new documents have been created to cover the requirements needs considering simulation types as Steady State, RMS, EMT, Harmonics, as well as provisions to mitigate issues of black box models.

The provisions do cover all PGM technologies and not only offshore wind:

- Generic and/or detailed simulation models reflecting the point of connection;
- Considerations for electrical components (AVR, PSS, governor) and other physical limits (fuel valve, pitch, and internal turbine limits) when they influence unit response;
- SPM/PPM type B equivalent models, with type C and D models encompassing both individual and equivalent models;
- Site-specific load models;
- Model aggregation based on technology type;
- Grey-boxed models complete with descriptions and minimum requirements for input/output.

For different simulation categories (Steady State, RMS, EMT), the documents specify both general provisions and specific ones tailored to various unit types, such as SPGM, SPM/PPM and demand facilities.

On the other hand, provisions for indirectly connected facilities are more focused on:

- Generic simulation models;
- Model validation, carried out by the relevant system operator;
- SPM/PPM models, exclusively for types C and D equivalent models;
- Model aggregation based on technology type;
- Black-box models with descriptions of input/output variables.

Additionally, the data collection procedure has been enhanced, primarily concerning the data questionnaire. The new questionnaire format ensures:

- Effective data integration;
- Minimized risk of inaccuracies;
- Potential for automated data collection.

2. Model Validation

The introduction of the model validation procedure offers a win-win scenario for Elia, Generation Owners, and Manufacturers, as it:

- empowers Elia to plan and operate a stable network with increased model accuracy;
- provides Generation Owners with greater confidence in the compliance and stable performance of their assets;
- offers clear guidance to Manufacturers in carrying out their tasks.

This document provides an overview of the new procedure, which encompasses the following models:

- RMS/Power Factory Models, both in aggregated and detailed forms.
- EMT/PSCAD Models, available in both aggregated and detailed versions.

To enhance robustness, the model validation procedure has been integrated into the entire compliance process, as illustrated in the below figure. The overall procedure is divided into four major steps:

- ***P1***: Initial model acceptance: General Perquisite for EON;
- ***P2***: Intermediate model performance validation: General Perquisite to ION;
- ***P3***: Commissioning and model validation: General Perquisite to FON;
- ***P4***: Post-commissioning model validation.

The model validation procedure takes place during P3. During this stage, site test measurements are collected and then compared against simulation results. Various simulation tests are conducted, and the deviation between simulated and measured data is calculated to ensure an objective assessment of simulation model accuracy. The deviations must meet or be less than the permissible deviations specified in the referenced norms, which, in this case, are the IEC 61400-27-2 norms, also in use in Germany and Ireland.

The results of these standardized tests are used to validate the simulation model's accuracy. The minimum requirements for controls include:

1. Active power control
2. Reactive power control
3. Voltage Control
4. Frequency Control

The final results of dynamic studies are submitted to Elia for approval in the form of a comprehensive report, including all mandatory tests, measurements, and simulation data. Parameters, settings, and models are considered validated when computer simulation results align with site test results within the allowed deviation. Both simulation and site test results are overlaid on the same plots using the same scale. Following the completion of site tests, the Grid user is required to submit a statement of compliance to fulfill the FON condition, along with the associated validation report and data/models (as built).

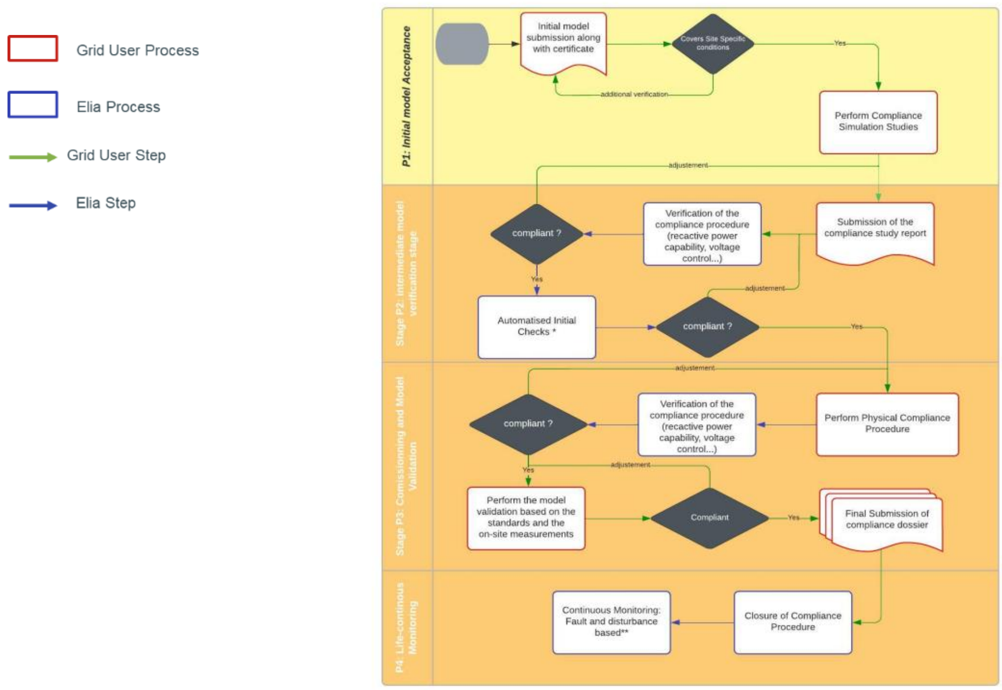


Figure 66 : Process for Model validation

4. Market design

4.1. Executive summary

To realize offshore ambitions in the North Sea and the other European sea basins, a massive deployment of offshore infrastructure will be needed. The market design has as key objective to make optimal use of this infrastructure in the interest of society. In line with European legislation, this objective materializes into allocating the transmission capacity in the most efficient manner (socio-economic welfare maximization) as well as into conveying the right dispatch incentive across timeframes (wholesales and balancing markets) such that the market dispatch accurately reflects the technical limits of the transmission grid.

To accommodate the integration of both offshore wind and interconnectors (such as the Nautilus interconnector with UK and the TritonLink interconnector with Denmark) onto the Princess Elisabeth Island in line with the above principles, the target market design encompasses three critical enablers:

- **Return of the UK to the European single implicit price coupling**. Following Brexit, cross-zonal capacity on interconnectors to the UK is currently allocated in an explicit manner. This leads to less optimal use of transmission capacity;
- **The application of an Offshore Bidding Zone** to manage the structural congestion embedded in a hybrid grid design;
- **The rollout of Advanced Hybrid Coupling**, which is already part of the legal framework for congestion management, to make most efficient use of the onshore grid capacity

Combined these three enablers foster full competition for the transmission capacity, both offshore and onshore, avoiding to apply an ex-ante split of capacities through forecasting. The ex-ante split of capacities leads to inherent inefficiencies and therefore socio-economic welfare loss. This is due either to over-allocation of transmission capacity requiring costly corrective measures at some moments, or to too conservative forecasts leaving capacity unused during other moments.

From a societal and legal perspective, the target market design thus allows for an efficient management of (structural) congestions and thereby an optimal use of the grid infrastructure.

Yet from the perspective of an investor into offshore wind, this societal optimum induces uncertainties due to price and volume effects. These effects are elaborated in various studies comparing an Offshore Bidding Zone versus a Home Market approach, but the focus in these studies is put on the congestion in the offshore grid. From our analysis, it turns out that congestions in the onshore grid shape the price and volume effects, notably through the competition effect induced by Advanced Hybrid Coupling.

A well-designed support mechanism, as intended in Belgium, is a fundamental piece of the puzzle to de-risk investments and to align the interests. At the same time, it is of paramount importance that this support mechanism does not create market distortions. In the case of the Princess Elisabeth Zone, these objectives are fulfilled thanks to the choice made by the authorities to implement a two-sided *capability-based* CfD mechanism.

The formal creation of the Offshore Bidding Zone stems from the structural congestion that is by design part of the hybrid set-up of the Princess Elisabeth Island. To initiate this formal process the scope and timing of the Offshore Bidding Zone has to be sufficiently certain. Multiple scenarios are possible, depending on:

- The exact go-live date of the Nautilus and TritonLink interconnectors;
- The feasibility to operate the Princess Elisabeth Zone as single node (coupling the offshore wind farms connected to the AC and DC side in the Princess Elisabeth Island) as this determines which part of the 3.5 GW offshore wind is subject to competition with import over the interconnectors;
- The policy choice of a return of the UK to the European single implicit price coupling. This is a pre-condition to avoid an ex-ante capacity split – and associated welfare loss due to forecast inefficiencies – on the connection between the Princess Elisabeth Island and the Belgian onshore grid. Such capacity split would be needed to feed on one hand an explicit coupling with the UK and on the other hand the European implicit price coupling. Aside from being less efficient, explicit coupling has major drawbacks when combined with a hybrid grid design. The drawback under a Home Market approach is that congestions are predictable and thus prone to market manipulation. The drawback under an Offshore Bidding Zone approach is that forecast errors distort the price formation in the Offshore Bidding Zone;
- Technological developments enabling a meshing of HVDC interconnectors (DC circuit breaker) as this determines the role of TritonLink in the Princess Elisabeth Island.

Elia expects an Offshore Bidding Zone to be implemented as soon as an interconnector whose capacity is allocated through implicit price coupling is integrated onto the Princess Elisabeth Island. This scenario is expected to materialize in the 2030-2035 horizon.

The related policy choice of a return of the UK to the European single implicit price coupling and technological developments are considered key enablers to realize the offshore ambitions of the North Sea countries.

4.2. Introduction

Sections 4.2, 4.3 and 4.4 provide a high-level description of the expected evolutions in the market design along with their consequences. Section 4.5 provides a more in-depth explanation.

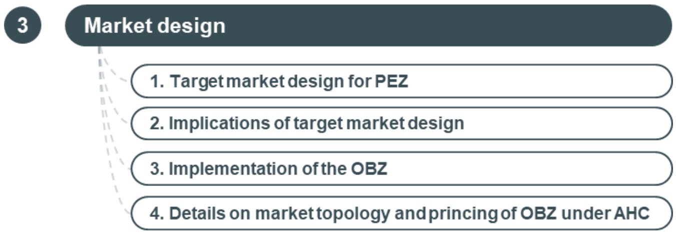


Figure 67 : Overview section market design

4.3. Target Market design

To realize the objectives of socio-economic welfare maximization and enabling an optimal dispatch, the market mechanism needs information on the scarce transmission capacity and needs a maximum degree of freedom to organize an economic arbitrage for the usage of this scarce capacity.

Applying these principles to the hybrid grid design of the Princess Elisabeth Island gives shape to three building blocks:

1. Offshore Bidding Zone (OBZ);
2. Implicit price coupling with the UK;
3. and Advanced Hybrid Coupling (AHC).

Figure 68 : Target market design for Princess Elisabeth Island Offshore Bidding Zone

When it comes to the integration of a hybrid grid design into electricity markets, two models can be considered:

1. **The home market model:** in this conventional arrangement, the offshore RES generation commercially and physically feeds into its home market, i.e. into the grid of the same country in whose territorial waters or Exclusive Economic Zone (EEZ) the park is located;

2. **The Offshore Bidding Zone (OBZ) model:** in which the offshore RES generation is situated in a separate bidding zone, being physically connected to several markets. This ensures that RES generation can flow to where it is needed and can be fully integrated into the market by simultaneously integrating renewable energy and using cross-border interconnections for trade.

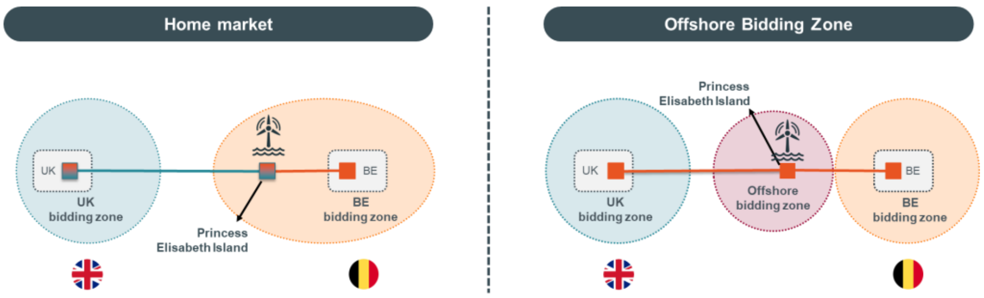


Figure 69 : Home Market and Offshore Bidding Zone market design

The Offshore Bidding Zone model is the superior model to obtain an efficient and consistent management of congestion as prescribed by European legislation. Bidding zones indeed form the cornerstone of the European zonal market model, and the bidding zone borders are to be set where structural congestion is present.

The hybrid set-up of the PEI by design contains structural congestion: full cross-border exchanges and full wind injection cannot be accommodated at the same time. An Offshore Bidding Zone model is here the appropriate choice, as a Home Market model would induce major inefficiencies:

1. Under a Home Market model, the offshore wind would physically inject all their offered energy in the Belgian bidding zone without consideration of the technical limits of the offshore infrastructure;
2. During capacity calculation, which starts two days ahead of real-time, Elia would have to ex-ante split the transmission capacity between PEI and the Belgian onshore grid based on an early wind forecast. Concretely, taking the Nautilus interconnector as example, the capacity to import from the UK to Belgium is determined by subtracting the forecasted infeed of offshore wind from the technical capacity of the HVDC link. This approach, where offshore wind is given ‘priority access’, mimics the normal

functioning of the market where the offshore wind is expected to be the most competitive generation source;

3. Forecast errors are unavoidable. In case of overestimation of the wind in the forecast, transmission capacity remains unused. In case of underestimation of the wind in the forecast, the technical limits of the network are no longer respected. This will become visible during the operational security analysis processes performed after the DA market coupling. Elia will have to intervene to realize a feasible dispatch solution, leading to a decrease in wind infeed and an increase in flexible generation on-shore. This results in increased fossil fuel generation and in redispatching costs to be borne by society.Below example illustrates the forecast error inefficiency. The high burden of operating the system makes a Home Market model less sustainable, less affordable and less reliable than the Offshore Bidding Zone model.

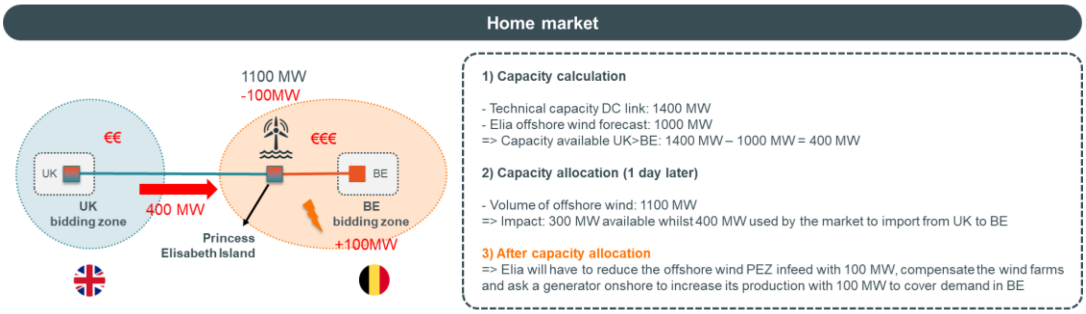


Figure 70 : Inefficiencies in a home market configuration

4.3.1. Implicit price coupling

The most optimal outcome for the socio-economic welfare can be reached via a single energy market where cross-border capacity and energy are implicitly coupled by a market coupling algorithm. This market mechanism is today in place in the EU + Norway for trades between bidding zones within this area. However, as a consequence of Brexit, the interconnectors between the United Kingdom (UK) and Europe and (Northern)-Ireland (NI) were excluded from the Internal Energy Market (IEM) and thus removed from the Singled Day Ahead Coupling (SDAC). The capacity on these borders to the UK are now offered in an explicit manner where market participants have to separately buy and nominate cross border capacity in order to exchange energy between the UK and Europe[15].

[15] *Explicit refers to the acquisition of capacity separately from the exchange of electricity. On the contrary, under an implicit allocation approach both capacity and exchange of electricity are allocated together. Some other mechanisms exist on the interconnector with Norway and to Ireland, but none of them are equivalent to the full price coupling that existed before Brexit.*

► Explicit coupling comes with inherent inefficiencies

Firstly, in explicit allocation market participants take decisions based on price forecasts. This sometimes leads to inefficient use of the interconnector's capacity, meaning electricity flowing from the expensive to the cheaper market (so called "adverse flows"), in particular when price differentials are small. Furthermore, the price forecast of market participants can be higher or lower than the real market spread that occurs between BE and UK power markets. This leads to an inefficiency for capturing (congestion rent) for the interconnector. Market participants valuation of the interconnector's capacity can be either higher or lower than the effective market spread leading to a value capture factor which can be lower or higher than 100%.

In addition, as in explicit auction the volume allocated is determined by the demand bids of market participants, it can lead to a different usage of the interconnector's capacity compared to implicit market coupling. In other words, even when the flow is in the right direction from price perspective, the allocated volume can be too high or too low compared to an optimal reference defined by the result of implicit market coupling.

► Explicit coupling has major drawbacks when combined with a hybrid grid design

Today explicit coupling can be operated in a fairly simple and stable manner given the point-to-point aspect of current interconnectors. In a hybrid grid design, however, an explicit coupling regime does not fit with a Home Market nor an Offshore Bidding Zone approach.

The Home Market model with explicit auctions is prone to market manipulation due to the predictability of the congestion that can occur on the leg PEZ – BE:

- As explained in the previous section, in the Home Market configuration the TSO has to make a forecast of the offshore wind production. This forecast defines the remaining capacity available for the explicit auction on the interconnector between Belgium and the UK;
- After the explicit auction, the volume of allocated capacity on the BE-UK interconnector is published. At this point in time both the information about the TSO's wind forecast and the results of the explicit allocation are publicly known. This situation creates a possibility for market manipulation by the OWF. The OFW can gain benefits if it would offer more volume to the DA implicit market coupling compared to the wind forecast made by the TSO;
- By doing so (and assuming the volume will be accepted in the DA implicit market coupling) the connection between the PEI and the Belgian onshore grid will be congested. Indeed, the sum of the allocated capacity via the explicit auction and the accepted wind volume in the DA implicit market coupling will surpass the transmission capacity of the connection between the PEI and the Belgian onshore grid;

- Normally the OWF should not offer more than his capability as this would result in a short position for which it will face an imbalance cost. However, the TSO will take congestion management measures to resolve the congestion, by reducing the schedule of the OWF and triggering an upward activation onshore. As TSO, Elia will remunerate the OWF at its marginal cost (~0€/MWh) and make an imbalance adjustment to the BRP perimeter of the OWF. The end result is that by its behavior the OWF will keep the DA revenues for the additional (fictive) volume it offered whilst the OWF will not be penalized for the imbalance due to the congestion management measure taken by the TSO;
- These unwanted effects are an inherent risk to a Home Market set-up with explicit auctions. In order to mitigate it, penalty schemes with close monitoring could be envisaged.

The combination of an explicit coupling with an Offshore Bidding Zone is inefficient and distortive:

1. Firstly, it does not lead to an efficient congestion management solution. Although the connection between PEI and the Belgian shore is formally a bidding zone border between the bidding zones OBZ and BE subject to the European implicit price coupling, Elia would have to ex-ante split the capacity of this connection to feed at one hand the explicit allocation with the UK and on the other hand the European implicit price coupling. Such capacity split would be based on the forecasted volume of the offshore wind. This naturally comes along with forecast errors resulting in loss of social welfare. In other words, whereas the inherent driver of an OBZ is to avoid forecast inefficiencies, this cannot be achieved under an explicit coupling regime.
2. Secondly, forecast errors distort the price formation in the OBZ. This distortion occurs when the forecasted volume of offshore wind is underestimating the volume of offshore wind bid into the market through the OBZ, As the offered volume of offshore wind then can only partially clear in the implicit allocation, the marginal price of the offshore wind determines the price of the OBZ. In other words, the price in the OBZ is set to ~0€/MWh as a result of a forecast error. Example:
   a. *Capacity of the connection between PEI and Belgian shore: 1400 MW.*
   b. *Forecasted volume of OWF: 1000 MW. This 1000 MW is made available on the bidding zone border OBZ – BE in the European implicit price coupling*
   c. *Offered volume of OWF: 1100 MW. From this 1100 MW there can at maximum be 1000 MW accepted. Price in the OBZ = ~0€/MWh.*

► MRLVC is not a scalable solution either

Under the EU-UK Trade and Cooperation Agreement (TCA), governing among others the cooperation in the area of energy following Brexit, EU and UK authorities intend to develop a new market design, being MRLVC. Volume coupling is an implicit allocation mechanism, but unlike price coupling it only determines cross-border flows, with prices determined in a subsequent step. The TCA itself does not specify further the design of the MRLVC yet puts forward the requirement that MRLVC can only have access to order book data for the UK and for the bidding zones directly connected to the UK. As MRLVC is not allowed access to order book data for bidding zones not connected to the UK, it is required to use a forecast for expected commercial flows between bordering bidding zones (i.e. connected to the UK) and the rest of the Internal Energy Market.

While MRLVC in itself would already be challenging to implement in current market topology, there is a high uncertainty on its scalability for the offshore grid with Offshore Bidding Zones. Like explicit coupling, also MRLVC is heavily reliant on forecasts, a factor that often results in suboptimal allocation of capacity, leading to the underutilization of vital infrastructure and inefficient allocation of offshore wind resources. The inherent driver of an OBZ, namely ensuring market arbitrage for the scarce transmission capacity, cannot be fully grasped.

In explicit trading, market parties bid in dedicated auctions to trade over the border and is a separate process from the Single Day-Ahead Coupling (SDAC). In MRLVC, the SDAC orderbooks from the bordering SDAC bidding zones are used, but the flows (and thus the trades) on the interconnectors between UK and SDAC bidding zones are fixed before the day-ahead auction. Under both designs, the flow on the UK borders cannot be used by the SDAC as a degree of freedom to further optimize welfare. Hence, neither design is compatible with AHC and would lead to an opportunity loss in the advantages presented in the next section for not being able to implement it.

Since MRLVC is a volume coupling and not a price coupling there is also no clarity, how any price information would carry over between GB, the OBZ and EU mainland preventing that the Offshore Wind Farm (OWF) is able to capture the real value of their electricity in the offshore bidding zone.

Another distinctive challenge in the case of the OBZ is the limited availability of local offers, often from a single source. This makes the OBZ more susceptible to inefficiencies stemming from explicit trading or MRLVC mechanisms when compared to larger bidding zones.

As a consequence, Elia sees explicit allocation and MRLVC as inefficient and not scalable for the offshore ambitions and that a full return to implicit price coupling within offshore bidding zones stands as the most scalable and efficient solution for realizing ambitious offshore wind energy goals. Elia further understands that this point of view is more and more becoming a common understanding. This transition is expected to not only enhance efficiency but also pave the way for a more seamless integration of offshore wind resources together with offshore hybrid infrastructure into the broader energy landscape.

Elia believes that a full return to implicit price coupling is the only scalable solution for offshore wind ambitions in the EU and the UK.

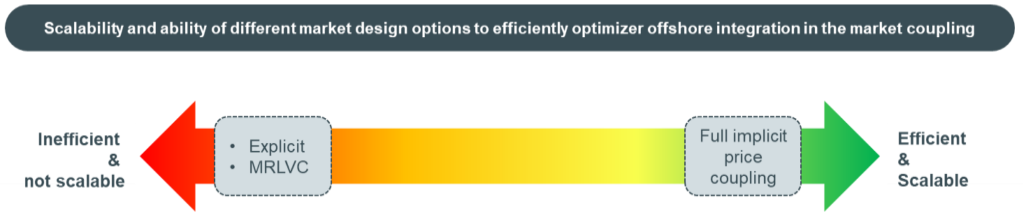


Figure 71 : Market design options for integration of UK interconnectors

4.3.2. Advanced Hybrid Coupling

Advanced Hybrid Coupling is already part of the target electricity market design in Europe as set in regulation

The implicit price coupling model's target solution in Europe comes along with the implementation of Advanced Hybrid Coupling. This concept originates from a need to manage the influence of cross-zonal exchanges between Capacity Calculation Regions (CCRs).

Each CCR is responsible for calculating the cross-zonal capacity for the bidding zone borders assigned to the CCR. However, cross-zonal exchanges on bidding zone borders external to a given CCR also create flows in the onshore grid of this CCR. For example, the bidding zone border between Norway and the Netherlands is assigned to CCR Hansa whilst cross-zonal exchanges through the NorNed HVDC interconnector will use capacity of the onshore grid in CCR Nordic and of the onshore grid in CCR Core since the electricity will not simply stop to flow at the landing point of the HVDC interconnectors, but will have to be distrusted further in the meshed AC grid on each side.

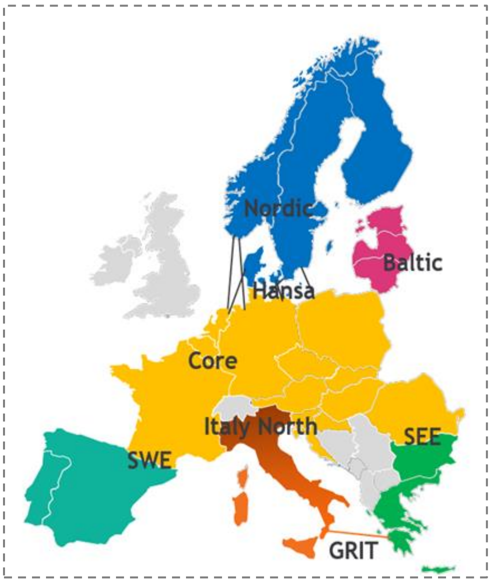


Figure 72 : Overview of Capacity Calculation Regions

There are two ways to take into account the use of capacity by borders external to a CCR:

1) **With Standard Hybrid Coupling (SHC),** the exchanges on the external borders and hereby their usage of the CCR's onshore grid are forecasted by TSOs during the capacity calculation process. The capacity of the onshore grid netted against this forecast is offered to the market coupling. Obviously, forecast errors translate to inefficiencies as either too little, or too much capacity was made available to the market, subsequently creating a loss of welfare respectively an increase in redispatching costs.

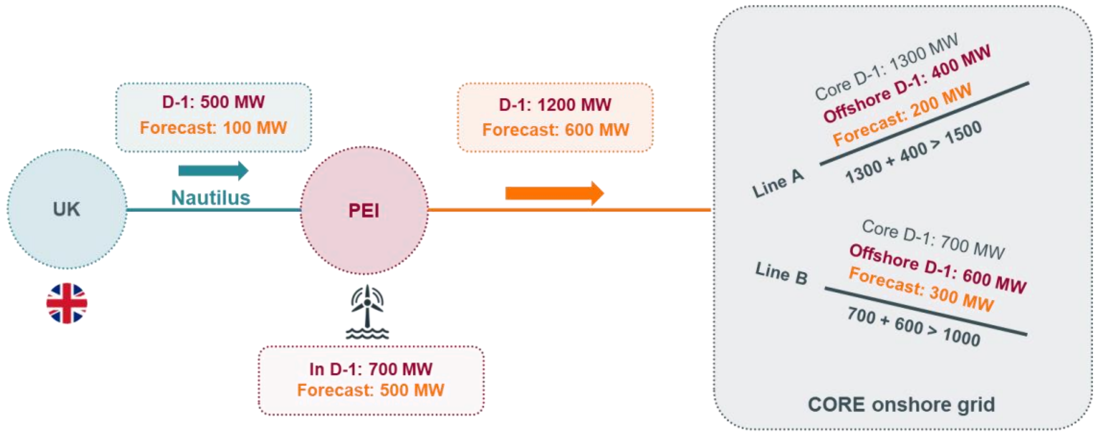
2) **With Advanced Hybrid Coupling (AHC)** there is no forecast needed anymore. During capacity calculation, the effect of an exchange over the external border on the onshore grid is made visible to the market coupling algorithm in exactly the same way as the effect of an exchange over an internal border to the onshore grid is made visible. For both internal and external borders the allocation algorithm has all information to do the arbitrage for the use of the scarce capacity of the onshore grid and to find the solution with the highest socio-economic welfare.

SHC is the historical way of working and currently implemented in CCR Core. The switch from SHC to AHC is planned for around 2025 in CCR Core and is part of the implementation of flow-based market coupling in CCR Nordic. However, as mentioned before, AHC is not compatible with explicit allocation nor MRLVC and thus can only be implemented on the interconnectors to UK in the event of a return to implicit price coupling.

► **Reaping the benefits of Advanced Hybrid Coupling is also necessary for offshore interconnectors**

For interconnectors to third countries such as the UK and Switzerland it is currently prohibited to implement AHC, even though the scalability of RES integration without it is highly questionable.

Taking the concrete use case of Nautilus and offshore wind in the PEZ, the OBZ solves the structural congestion between the PEI and the Belgian coast by enabling competition between import from Nautilus and offshore wind. Yet the OBZ does not manage the congestion in the onshore grid of CCR Core. Without the application of AHC, Elia would still need to forecast the flow resulting from the combination of offshore wind and import/export over Nautilus. This forecast impacts the capacities made available for exchanges across the bidding zone borders of CCR Core. When the offshore wind and/or the import/export differ from the forecast, major inefficiencies occur. Unused capacity in the onshore grid implies welfare losses whilst congestion in the onshore grid implies redispatching costs.



Capacity calculation
Capacity available for all market exchanges: line A = 1500 MW; line B = 1000 MW
Forecast infeed PEZ: 600 MW, using 200 MW on line A and 300 MW on line B
Capacity available for exchanges in Core: line A = 1300 MW and line B = 700 MW

Capacity allocation (1 day later)
Capacity on lines A & B fully used for Core exchanges
Infeed from PEZ: 1200 MW instead of 600 MW
Impact: 200 MW overload on line A and 300 MW overload on line B

After capacity allocation: redispatch
Core TSOs coordinate a least-cost solution that takes care of all congestion at once in the Core onshore grid. If the optimizer identifies that reducing the offshore infeed is part of this optimum the offshore infeed will be reduced.

Figure 73 : Illustration of forecast error leading to congestion grid in CCR Core

The example illustrates how a forecast error leads to congestion in the onshore grid in CCR Core. This congestion is solved through a coordinated least-cost solution on CCR level. Applying the principle of optimization, the reduction of offshore can but is not by default part of the solution.

Note the example uses the day-ahead timeframe to illustrate the forecast inefficiency. The forecast inefficiency will however expand into the intraday timeframe and the balancing timeframe as Core TSOs ought to implement in the coming years a recalculation of capacities for these timeframes. On top of an increase in redispatching costs, inherent limitations related to having insufficient time and/or means to coordinate and alleviate congestion will become apparent and aggravate the impact of forecast inefficiencies.

The only way to avoid these inefficiencies in the allocation phase is through the application of AHC, which will remove the need for TSOs to forecast the flows coming from offshore interconnectors and thereby will foster efficient competition between all borders, thus internal and external, for the usage of scarce capacity of the onshore grid. Market arbitrage is made possible irrespective of whether the border is between onshore bidding zones, between an offshore bidding zone and an onshore bidding zone or between offshore bidding zones, and irrespective to which CCR the border is assigned.

4.3.3. Resulting target market topology

All the building blocks together converge into a target market topology for the Princess Elisabeth Island (PEI). Below picture illustrates this target market topology in relation to the planned grid design thus accounting for:

1) The connection of 3.5 GW offshore wind onto the PEI;
2) The integration of the Nautilus interconnector onto the PEI;
3) The meshing of the TritonLink interconnector onto the PEI. Initially TritonLink is realized as a direct interconnector between Denmark and Belgium, physically passing through the PEI but not electrically connected. Technological developments (DC circuit breaker technology, multi-terminal HDVC) are expected to over time make it possible to electrically connect TritonLink to the PEI.

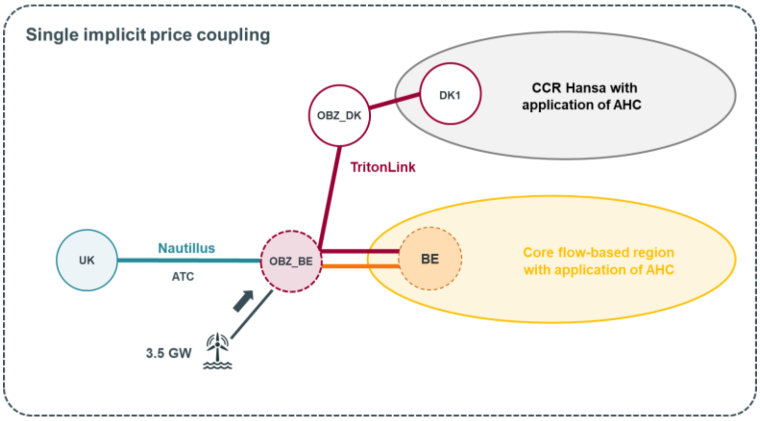


Figure 74 : Target market topology for Princess Elisabeth Island

The establishment of the Belgian offshore bidding zone OBZ _BE is at the heart of this picture. The uncertainties regarding its scope and timing are addressed in Section 4.5. The establishment of an OBZ_DK on the Danish side of the TritonLink interconnector is added for the sake of completeness and reflects the ambition to apply a hybrid grid design structure on the Danish side.

Irrespective to which CCR these new offshore bidding zones and resulting bidding zone borders are assigned, the AHC competition effects comes into play. Indeed, the connection with the Belgian bidding zone induces the application of AHC in CCR Core, and the connection with the Danish bidding zone induces the application of AHC in CCR Hansa. Concretely this implies that the dispatch of the offshore wind is also driven by its impact on the onshore grids of CCR Core and CCR Hansa.

Note that:

1. *When on both sides of the interconnector the market topology applies AHC, which is the assumption for TritonLink, this is defined as 2-sided AHC;*
2. *If the bidding zone border OBZ_BE - BE is assigned to CCR Core the application of the competition effect is legally labelled as Evolved Flow-Based (EFB). EFB is conceptually the same as AHC but then applied to a bidding zone border internal to the CCR. The ALEGrO interconnector between Belgium and Germany is a first implementation of EFB in the CCR Core;*
3. *Technically speaking AHC is implemented in the market topology by means of a virtual hub, see details in Section 4.6. For simplification purpose the notion of virtual hub is omitted from above picture.*

Furthermore, the assumption for Nautilus is that on the UK side the market topology remains ATC-based. The set-up where AHC is applied on one side of the interconnector and ATC is applied on the other side is defined as 1-sided AHC.

Finally, the ongoing market reform in the UK may result in a more granular market topology on the UK side. Any possible implications of such market reform are out of scope of this report yet are not expected to impact the rationale outlined above.

4.4. Implications of the target market design

The scope of a classical OBZ versus HM comparison focuses on the offshore grid, explaining that the offshore wind in an OBZ competes with import/export over the interconnector and as a result is subject to price and volume effects. The price effect is explained as the price of the OBZ converging to the lowest price of the surrounding bidding zones. The volume effect is explained as negative prices in the interconnected market resulting in imports from this market outcompeting the offshore wind.

Whilst this is conceptually true, the effect of an OBZ as congestion management measure cannot be looked at in isolation. The OBZ has to be looked at together with the congestion management measure taken to ensure an efficient allocation of the onshore grid capacity, namely the implementation of AHC.

This section summarizes the resulting price and volume effects, and sketches through some examples how they can be mitigated through the application of a 2-sided capability based CfD support mechanism. An exhaustive explanation with concrete toy-examples on how the pricing and the clearing of offshore wind in the OBZ will take place in the foreseen target market design is provided in Section 4.6.

4.4.1. Price effects

Advanced Hybrid Coupling will consider the impact of more/less wind or more/less import/export from or to other bidding zones via the OBZ on the entire grid of the CCR(s) to which the OBZ is connected[16]. The prices determined in the welfare optimization during market coupling thus reflect competition for the entire grid of the involved CCR(s), and not just competition for the grid in the bidding zones directly connected to the OBZ.

In general, if market exchanges originating from the OBZ, being either caused by wind or import/export, are loading the critical network elements from the involved CCR(s) more compared to market exchanges between onshore bidding zones, the price in the OBZ has to be lower to make the market exchanges originating from the OBZ part of the optimal welfare solution. If the OBZ has a lower (or even relieving) impact on the loading of the critical network elements, even a high price in the OBZ can match with market exchanges from the OBZ being part of the optimal welfare solution.

Pricing in the OBZ is thus influenced by more than just the prices in the bordering bidding zones. It is possible that the price in the OBZ is “out of bounds” compared to the prices of the bordering bidding zones. Taking Nautilus as an example, in the hybrid grid design of the PEI, the price in the OBZ can be lower than the minimum of the Belgian and UK prices or higher than the maximum of both. The price in the OBZ can even be negative whilst the UK and Belgian prices are positive. This can have a positive or negative impact on the revenue of the offshore wind in the OBZ yet may be harder to predict over long periods of time.

16 *The technical way of taking into account these variations of import/export will be by a change in net position of a virtual hub, which is further explained in section 4.5*

4.4.2. Volume effects

Offshore wind included in the OBZ will also face volume effects in the market coupling. The volume allocated can differ from the volume the offshore wind farm expected to produce and offered to the market. The volume effect has two drivers:

1) Competition between offshore market exchanges and onshore market exchanges for the use of the onshore grid. This follows from the application of AHC as it applies the flow-based market coupling principles also upon the OBZ;
2) Competition between offshore wind and import from the UK. In case the entire UK market sits at negative prices, the import from UK outcompetes the offshore wind which is ought to bid at around zero €/MWh marginal cost.

The volume effects and negative prices inherent to the application of AHC are a feature of an efficient market model.

The volume risk and negative prices due to an inflexible merit order and due to distortive support mechanisms for RES (incentivizing to not bid at the true marginal cost of production) are not a feature of an efficient market model. The ambition of TSOs and policy makers must be to phase them out by ensuring RES reacts properly to price signals, by unlocking flexibility at consumers and industry, and by removing distortive effects from support mechanisms. At the time of launching this consultation, such principles are likely to be included in the electricity market design reform on EU side. They are also discussed on UK side.

4.4.3. Role of 2-sided capability based CfD

The evolutions in market design represent essential factors in ensuring the most beneficial solution for the whole society. However, they are expected to increase uncertainties on the offshore wind farms revenues over the long term. Basically the way AHC will be defined in the capacity calculation methodology and the capacity made available will have price and volume effects, which are naturally difficult to forecast since they are highly dependent on where in the future congestion occurs in the onshore grid and on how the capacity calculation methodology will further evolve (minimum,capacity requirements, the extent to which internal network elements can limit capacities, etc.).

The tendering principles for the Princess Elisabeth Zone propose a contract for difference to stabilize the wind farm’s revenues and protect them from such risks. One of the most important elements in the proposed high-level design is that the settled volume is based on the farm’s “Available Active Power” or “AAP”. Rather than actual injection, it is a metric for the potential injection a wind farm could have delivered (accounting for e.g. wind speed, park topology, outages,...) even if the actual injection is reduced.

This makes it characteristic of a "capability-based CfD", as for example mentioned and supported by ENTSO-E [17], and has a number of important advantages over injection as a metric with regards to risk coverage for wind farms. This also appertains to the volume and price effects in an OBZ and under AHC. In addition, it ensures more efficient bidding and dispatch behavior.

Some examples using a fictional strike price of 80 €/MWh for the CfD and 400 MWh of potential injection (= AAP) illustrate this further. For further clarification: the strike price is the price a candidate offers in the tender for offshore wind and represents the revenue per MWh they will be guaranteed under the CfD. To this end, the wind park presumed to make revenues in the market according to a reference price over the course of the contract. The CfD will then settle the difference between the reference price and the strike price, via either payments from the state to the wind farm (if the reference price is lower than the strike price) or payments from the wind farm to the state (if the reference price is higher than the strike price).

For the volume effects, the use of AAP decouples the CfD payments from actual injection. Therefore, if for example the import from UK towards Belgium outcompetes the offers made by wind because of negative pricing, the volume the wind farms were not able to sell is still covered by the CfD (to be noted that there is no material loss of market revenues even if the wind is not selected by the market, since the non-selection implies that the market price in the OBZ is lower than the bid price, i.e. zero or negative if the wind bid at zero).

Example using a fictional strike price of 80 €/MWh for the CfD and 400 MWh of potential injection: *if the import possibilities towards Belgium would be saturated and there is a substantial supply offer in UK below -30 €/MWh, this would mean the market coupling algorithm will prefer flows from UK at negative price towards Belgium over the 400 MWh offer made by wind at 0 €/MWh[18]. This results in a volume effect by which the OWF will be requested to produce lower volumes than the 400 MWh offered. However, even if the capacity is not allocated to wind (and injection in the end is even reduced to 0 MWh), the AAP remains at the volume the wind park could have produced and reimburses the difference payment of the 80 €/MWh with respect to the OBZ -30 €/MWh[19] clearing price for the 400 MWh of potential injection. Section 4.5.1.4 depicts a similar situation.*

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[17] *Referred to in their position paper on the 2023 Electricity Market Design Reform, available on: https://www.entsoe.eu/news/2023/04/03/entso-e-s-position-on-the-ec-proposals-on-electricity-market-design/*

[18] *In practice, AAP is a real-time metric, whereas the volume offered in Day-Ahead is a forecast. Due to forecasting errors, it is therefore unlikely that the AAP will match the volume bid in Day-Ahead. The example ignores this for simplicity. However, it should be noted that a CfD based on injection does not mitigate this and retains a worse coverage of risks overall.*

[19] *The details of the CfD are not yet known at this stage, but it could be argued that it reimburses up to a reference price of 0 €/MWh, since the -30 €/MWh in this example is not a cost the windfarm suffers if it bids at real cost.*

Under AHC, it could be that wind is not selected (and prices are negative) even if prices of surrounding bidding zones are all positive. This is possible if an increase of export from the CORE Flow-Based region to the UK would alleviate constraints in the region and therefore allow more exchanges within CORE and if that would be a more welfare optimal solution (see Section 4.6.2.3). In that case, the wind will also not be selected in the Day-Ahead clearing. However, the same logic as in the above example applies to such a case (i.e. imagining the clearing price for the OBZ under AHC is -20 €/MWh as in the referred case).

Note that, as mentioned in the previous section, the price under AHC could also be higher than any surrounding bidding zone. It should further be noted that wind would still have an incentive to be selected and inject at any price higher than its (close-to-zero) cost. If the example clearing price of the OBZ is for example 20 €/MWh, the wind farm would only get 60 €/MWh (strike price 80 €/MWh – OBZ price 20 €/MWh) from the CfD mechanism for the 400 MWh of capability, but would need to also sell that 400 MWh to get the extra 20 €/MWh to arrive the strike price of 80 €/MWh. The wind farm should be able to obtain the 20 €/MWh by selling in the market of the reference price (e.g. if the reference price is the Day-Ahead Price, by selling in Day-Ahead). This example shows that CfD revenues are a complement to market revenues and only both together ensure an income per MWh equal to the strike price.

The difference payments should both protect against structurally low prices for the wind farms and avoid more payments from the state than necessary to support the project if prices are structurally high over the period, as it aims at levelling out reference price income with the strike price. As a result, it protects against both the risk of revenue shortage and avoids revenue volatility. In addition, the capability-based CfD does not give incentives to inject under negative imbalance prices (i.e. when there is a surplus of production in the system and excess injection suffers a cost), nor do negative price occurrences affect CfD revenues. This is not the case in injection-based CfDs, where a wind farm loses the CfD payments for every MWh not injected and for which many designs have a “cut-off” price (e.g. 0€/MWh) below which support payments are discontinued.

Finally, system or regulatory evolutions can affect price levels in the OBZ and the volume clearing for offshore wind. The capability-based CfDs independent volume reference and difference payment also protects against these types of risks.

Note on Transmission Access Guarantees: *The 2023 European Market Design Reform proposal contains a provision to permit the use of congestion income for funding a Transmission Access Guarantee or “TAG” for wind farms. Engie Impact put forward this design at the behest of the European Commission to* *analyse ways of congestion income sharing20. The purpose of a TAG is that wind farms would get compensated if in-sufficient grid capacity is available for them to export their wind production. In addition to the unclear scope and detailed design of TAG, it is understood TAG would only compensate for very specific volume risks, at a price which is likely to be rather theoretical. It is furthermore relatively certain that it does not provide coverage of volume risks due to price competition or price risks in an OBZ. The capability-based 2-sided CfD by comparison provides exhaustive risk coverage all in a single mechanism.*

4.5. Implementation of the OBZ

Offshore Bidding Zones will be an enabler to deploy a more and more meshed-oriented offshore grid infrastructure. With the PEZ hybrid set-up, Elia prepares this future and strongly believes an OBZ in Belgium will become a necessity and ultimately a reality. This section explains the uncertainties in relation to which part of the PEZ is subject to an eventual implementation of an OBZ and by when an OBZ will arise.

Furthermore, it is important to be prepared once the trigger(s) to realize OBZ materialize. This section identifies which legal process ought to be followed for deciding upon the creation of an Offshore Bidding Zone and portrays some considerations for its further implementation.

4.5.1. Key uncertainties

Aside from the timing of the realization of the Nautilus and TritonLink interconnectors, three key drivers / uncertainties influence the timing and scope of the OBZ:

1) Feasibility to operate the PEZ as a single electrical node;
2) Return of UK to the European single implicit price coupling. The market topology under explicit coupling is not expected to be combined with an Offshore Bidding Zone, at least not during the period where the Nautilus interconnector with the UK is the sole interconnector integrated onto the PEI;
3) Technological developments regarding DC circuit breaker technology and multi-terminal HVDC, and associated challenges of HVDC interoperability across multiple vendors. A stable and mature solution is required to electrically connect TritonLink to the PEI.

[20] *The report on TAG is available on: https://energy.ec.europa.eu/system/files/2022-09/Congestion%20offshore%20BZ.ENGIE%20Impact.FinalReport_topublish.pdf*

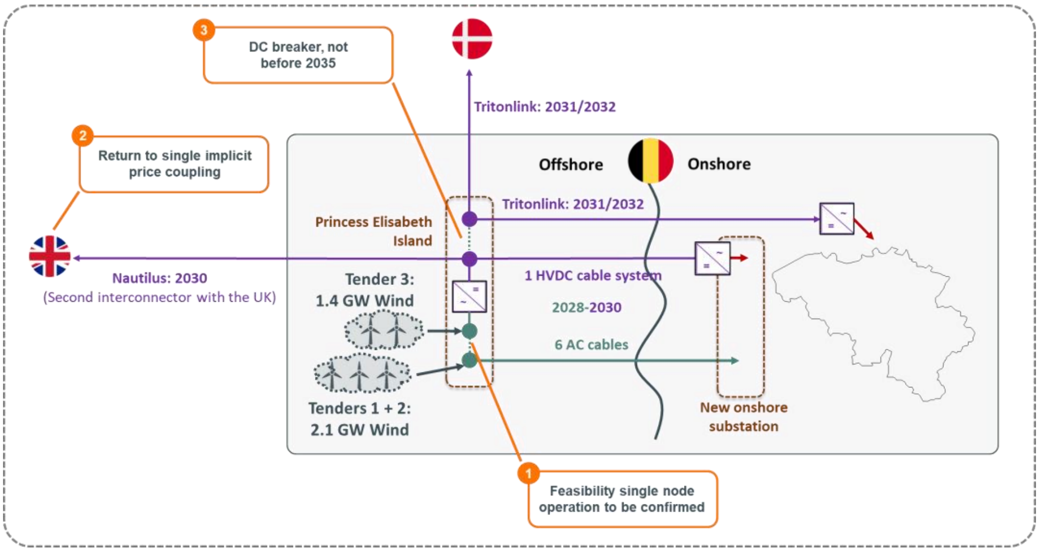

Figure 75 : Key uncertainties influencing the timing and the scope of the Offshore Bidding Zone for Princess Elisabeth Island

4.5.2. Scope of OBZ

The ambition is to connect 3.5 GW offshore wind to the PEI by 2030 and operate the PEI as a single electrical node. The technical feasibility of the single node operation is subject to confirmation by the HVDC system supplier during the detailed technical design phase.

In case the single node operation is feasible the full 3.5 GW offshore wind will share the capacity between the PEI and the onshore grid with the interconnectors that over time are integrated into the PEI. First the offshore wind shares the capacity of 1 HVDC cable system and 6 AC cables with Nautilus. Over time, when DC circuit breaker technology enables the meshing of the Triton interconnector, the offshore wind shares the capacity of 2 HVDC cable systems and 6 AC cables with both Nautilus and Triton.

In case technical limitations make the single operation (at first) infeasible, Elia will operate (at first) the PEI in a split configuration thus with two electrical nodes. In this scenario the 2.1 GW offshore wind of the first two tenders are brought to shore via the 6 AC cables and remain under a Home Market model as they are detached from the HVDC system and thus detached from Nautilus and Triton. The 1.4 GW offshore wind from the third tender injects into the HVDC system and is thus part of the OBZ as it shares the capacity of the connection to shore with Nautilus and Triton.

4.5.3. Timing of OBZ

The key driver for the OBZ is the integration of an interconnector whose capacity is allocated through implicit price coupling. The OBZ can indeed only fulfil its objective of enabling efficient market arbitrage if all the market exchanges making use of the connection between the PEI and the onshore grid are subject to implicit price coupling.

► Earliest scenario: 2030

The earliest scenario is one where the following two events materialize:

1) The realization of the Nautilus interconnector as per its current planning;
2) Return of the UK to the European single implicit price coupling. There is currently no indication that it would be decided, nor of a timing to make such policy decision.

► Later scenario: 2035

In case the uncertainty on the return of the UK to the European single implicit price coupling remains by 2030-2035, the Nautilus interconnector by itself will not trigger the creation of an OBZ. The trigger is then the meshing of Triton into the PEI, which requires two events to materialize:

1) The realization of TritonLink, currently under study with indicative timing 2031-2032;
2) Technological developments enabling the meshing of TritonLink into a multi-terminal HVDC set-up – not expected before 2035.

Note the OBZ in such scenario enables market arbitrage between TritonLink and offshore wind, yet the forecast inefficiency of dividing transmission capacity to two different allocation processes (explicit coupling with UK, implicit price coupling in Europe) remains.

► Implications for the market topology of PEZ

It is possible the offshore wind is temporarily connected in a Home Market configuration. In a scenario where the offshore wind is connected whilst there is no certainty about the materialization of the driver(s) for an OBZ, the offshore wind is connected first in Home Market. When at a later stage there is certainty about the materialization of the driver(s) for an OBZ, the OBZ implementation trajectory will determine the end of this temporary period.

In a scenario where the offshore wind is connected first and early in the process there is certainty about the materialization of the drivers for an OBZ, it becomes an implementation choice. Either the OBZ implementation trajectory is synchronized to the arrival of the offshore wind implying there is no temporary period where the offshore wind is connected in Home Market. Either the OBZ implementation trajectory is synchronized to the integration of the interconnector implying the offshore wind is connected in Home Market until the interconnector is integrated.

4.5.4. Legal process to determine OBZ

The following EU regulations are relevant for the determination of bidding zones:

1) Regulation (EU) 2015/2022 establishing a guideline on Capacity Allocation and Congestion Management (CACM). Articles 32 and 34 of the CACM set out rules on review of bidding zone configuration, yet this is a very heavy, complex and lengthy process;
2) Regulation (EU) 2019/943 on the internal market for electricity, part of the Clean Energy Package (hereafter Electricity Regulation). Electricity Regulation Article 14 offers the possibility to apply a leaner process.

To establish an OBZ the straightforward approach is to use the lean process offered by Electricity Regulation, initiated by the creation of a structural congestion report by the national TSO.

The rationale behind it is that by default bidding zone borders need to be applied to deal with the structural congestion. In order to establish an OBZ in principle it suffices to justify that the network elements between the PEI and the onshore Belgian bidding zone contain structural congestion. As the PEI is a hybrid solution, the structural congestion between the PEI and the onshore Belgian bidding zone is present by design.

Practically speaking, the process contains the following steps:

- **Step 1**: Elia delivers a structural congestion report;
- **Step 2**: CREG approves the structural congestion report. This comes along with a public consultation as per national rules;
- **Step 3**: Elia and CREG notify the relevant transmission system operators and relevant regulatory authorities that, on basis of the approved structural congestion report, Belgium initiates a review of its bidding zone configuration;
- **Step 4**: Belgium as Member State has 6 months to consult the relevant stakeholders, take a reasoned decision on the creation of an OBZ and notify this to ACER & EC. The decision should mention an implementation date;
- **Step 5**: Publication of the decision.

As part of this process, it is to be clarified whether ‘relevant’ TSOs, NRAs, and Member States materialize as ‘neighboring’ or if it concerns a larger geographical scope up to the whole Core CCR. Experience feedback from similar use cases will be helpful. A first concrete application is the Danish case of establishing an offshore bidding zone for the Bornholm Energy Island.

4.5.5. Implementation considerations

To initiate the formal process to determine the OBZ the scope and timing has to be sufficiently certain. Elia will monitor aforementioned drivers / uncertainties in alignment with authorities and continue to inform its stakeholders. Based on current information, Elia expects it will take beyond the timing of the (first) tender to get sufficient certainty.

After the formal process to establish the OBZ, an implementation track follows in which:

1) The OBZ and the new bidding zone borders need to be formally assigned to a capacity calculation region. This requires an amendment to the pan-EU methodology of CCR determination;
2) The OBZ and the new bidding zone borders have to be integrated into the capacity calculation and allocation processes.

Possibly amendments are needed to the regional methodologies. This can only be properly assessed closer to the go-live date of the OBZ, because the baseline of capacity calculation and operational security processes is massively changing in the coming 5 years at least in the Core CCR.

The lead-time to run the formal process to define and implement the OBZ is estimated at 2-3 years. The implementation part is however dependent on regional / pan-EU decision-making and prioritization and could take more time in case of structural / controversial amendments to regional methodologies and/or concurrent developments in the implementation pipelines.

4.6. Details on market topology and pricing of the OBZ under AHC

This section aims to provide more understanding of the price and volume effects in the OBZ under AHC. First the principles of flow-based pricing are explained. As part of these principles the occurrence of non-intuitive flows and how such flows contribute to a more efficient usage of the capacity of the onshore grid and thus to a more optimal market outcome is clarified. In the next step the concept of virtual hubs is introduced. Virtual hubs are virtual bidding zones which are used to model AHC into the market topology and are the tool which allows the market coupling algorithm to create efficient competition for the usage of scarce capacity of the onshore grid. Finally, the different price and volume effects taking place in the OBZ are illustrated with easy-to-understand examples building upon the previously introduced concepts of flow-based pricing, non-intuitiveness and virtual hubs.

4.6.1. On price differences under AHC

4.6.1.1 Flow-based can be non-intuitive

For the below discussion, we assume that welfare maximization price coupling is implemented between SDAC and UK using the OBZ concept under AHC, as this is the theoretical target model for hybrid off-shore interconnectors. We expect the reader to be already somewhat acquainted with the notion of "non-intuitive prices" under flow-based market coupling, and merely depict here how non-intuitiveness would apply to the combination of AHC and OBZ.

As a reminder, a solution is defined as "non-intuitive" when the sum of the net positions of the cheapest areas is negative. A market result is for example non-intuitive when the area with the lowest market clearing price is importing (while one would intuitively expect the cheapest markets to be exporting). This peculiarity is a direct consequence of the "flow-factor competition" and is derived from the duality conditions of the welfare maximation problem, and in particular the intrinsic relation that exists already today between the clearing prices within a flow-based area:

$$\mathrm{P_a} - \mathrm{P_b} = \sum\nolimits_{\mathrm{i} \in \mathrm{CB}} \left(\mathrm{PTDF_{b,i}} - \mathrm{PTDF_{a,i}}\right) \mathrm{Sp_i} \qquad \forall \mathrm{a, b}$$

Where

- *P_a is the market clearing prices of area a;*
- *$PTDF_{a,i}$ is the flow factor of area a over the critical branch i (part of the set of critical branches CB);*
- *Sp_i is the dual variable / shadow price of the flow-based constraint of the critical branch branch i (representing the cost impact of the constraint over the welfare objective function).*

Because of this relation, the price differences between pairs of hubs in a flow-based region are interlinked by their respective flow distribution factors, and the contribution of a given price difference between bidding zones to the welfare objective function is weighted by its relative impact over the grid constraints by the means of the shadow prices.

4.6.1.2 Simple example of non-intuitive prices

The following example illustrates non-intuitivity composed by 3 nodes (denoted BE, NL and VHBE (Virtual Hub BE)) in a triangular setup, where all lines have equal impedances. We assume that the critical branch between VHBE and NL is the scarcest capacity and is therefore the only grid element which is constrained, with an available margin of 100MWh.

Given the equal impedances, the grid constraint can be written as follows

$$-100 \leq \tfrac{1}{3}\mathrm{Nex}_{\mathrm{BE}} + \tfrac{2}{3}\mathrm{Nex}_{\mathrm{VHBE}} + 0\mathrm{Nex}_{\mathrm{NL}} \leq 100$$

Where

- Nex_a *is the net export of area* a*;*
- Nex_{VH_a} *is the net export of the virtual hub a.*

This means that one third of the export from BE to NL uses the constrained line, and two third of the export from VHBE to NL uses this line (see Figure 76).

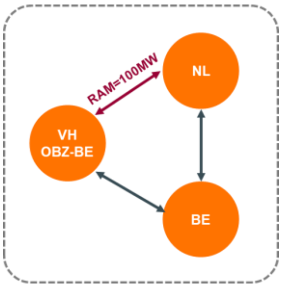

Figure 76 : simplistic flow-based example composed by 3 hubs and 3 lines of equal impedances

Because of the flow-based price relation explained above, the price difference between NL and VHBE will always be exactly the double of the price difference between NL and BE
(NB: this property holds for any of possible shadow price (SP) value, as the SP is variable on both side of the third equation below)

- $P_{NL} - P_{VHBE} = \frac{2}{3} Sp_1$
- $P_{NL} - P_{BE} = \frac{1}{3} SP_1$
- Hence $SP_1 = \frac{3}{2}(P_{NL} - P_{VHBE}) = 3(P_{NL} - P_{BE})$
- and $(P_{NL} - P_{VHBE}) = 2(P_{NL} - P_{BE})$

Economically, this is justified because – given that an export from VHBE to NL uses twice as much of the scares grid capacity compared to an export from BE to NL, an export from VHBE is economically efficient if it provides exactly twice as much of the value/welfare as an export from BE.

Making this more concrete in a toy example which is visualized in the figure below. For this example following simple orderbooks are supposed:

- NL: buy 3 000MWh at 100€/MWh
- BE: sell 3 000MWh at 80€/MWh
- VHBE: sell 3 000MWh at 70€/MWh

With this data, the grid constraint is in any case binding and thus importing the full 3 000 MWh demand to NL is impossible due to the grid constraint. In the welfare-optimal solution that takes into account the constraint of the grid, BE exports 300MWh; NL can only import 300MWh and VHBE has a neutral net position. In this solution the total welfare generated is equal to 300x100-300x80=6000€ (See Figure 2).

Clearing prices are deducted from the dual formulation of the welfare maximization problem which comprises a set of pricing constraints. For example, clearing prices are such that - in each area - they are below (respectively above) or equal to the locally accepted sell (resp. buy) orders; and are above (resp. below) or equal to the locally rejected sell (resp. buy) orders. This is often referred to as “in the money orders are accepted and out of the money orders are reject” (from which one can also deduct that partly accepted orders are at the money and set the clearing price). Such properties ensure that clearing prices are coherent with the acceptance/rejection of orders. Further, prices respect the flow-based price properties described above, such that optimal prices respect the flow factor competition.

For BE and NL, as the local orders are partially accepted (i.e. they are partly accepted and partly rejected), these orders are marginal and set the clearing prices for BE to 80€/MWh and for NL to 100€/MWh. The VHBE clearing prices must not only be at most 70€/MWh (i.e. the price of the rejected sell order in VHBE), but must also be set such that the price difference between VHBE and NL is the double of the price difference between BE and NL as defined by the FB pricing principles of the formula above. This is why VHBE clears at 60€/MWh.

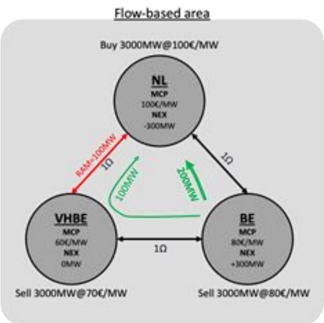

Figure 77 : ⅓ of the flow from BE to NL uses the constraining line.

To get more intuition over these results, imagine that VHBE would be exporting. Its order can only be partially accepted since the full 3000 MW cannot be exported due to the grid constraint, hence VHBE would clear 70 €/MWh. The maximal possible export of VHBE would be 150 MWh providing a welfare of 150x100-150x70=4500€, which is lower than the optimal solution. If we start with this solution where VHBE exports, a reduction of 1MW of this export from VHBE to NL reduces the welfare by 100-70=30€. But this frees up the tie constraint such that an addition of 2MW extra export from BE to NL (which generates 2x(100-80)=40€ of welfare) becomes possible. It is therefore advantageous from a welfare perspective to increase the export of BE, even though the price difference is smaller, because the export capability of BE is the double of the export capability of VHBE. This is so as long as the price difference between

VHBE and NL is less than the double of the price difference between BE and NL, resulting in a clearing price of 60 €/MWh. Consequently, VHBE ends up with a net position of zero since this clearing price is not high enough for the sell bid in the VHBE. Its clearing price of 60€/MWh is not defined by a marginal order, but by the flow-based price property described above. This latter price means that (everything else being equal) a sell order in VHBE will be accepted at a price of at most 60€/MWh. This is logical as with such a price, it would generate at least the same welfare as a flow with doubled volume from BE to NL.

Similarly, if the price of the BE order would be at least 85€/MWh (everything else being equal), it would become more profitable to clear the order in VHBE at 70€/MWh as only then the price difference between VHBE and NL is twice the price difference between BE and NL.

4.6.2. Non-intuitiveness pricing in a Flow-based region

The next example aims to explain the notion of non-intuitiveness. It builds on a further modification of the example in the previous section. In addition to the previous example a buy order in the VHBE at a price above the clearing price of 60€/MWh is added. Logically, such an “in the money order” should be accepted. To further illustrate the notion of non-intuitiveness, the orderbooks in this example become:

- NL: buy 3 000MWh at 100€/MWh
- BE: sell 3 000MWh at 80€/MWh
- VHBE: sell 3 000MWh at 70€/MWh
- (NEW) VHBE: buy 150MWh at 65€/MWh

With this modified data (see Figure 78) prices are unchanged (NL clears at 100€/MWh; BE clears at 80€/MWh and VHBE clears at 60€/MWh) but VHBE now imports 150 MWh as the buy order in VHBE is fully in the money hence fully accepted; and BE exports 600MWh while NL imports 450MWh. This is non-intuitive because VHBE is the cheapest market and is importing (while intuitively one would expect the cheapest market to be exporting). What happens here is that the non-profitable trade from BE to VHBE (which implies a negative welfare of 150x65-150x80= -2250€) frees up capacity over the tie constraint (-150MWh/3=-50 MWh going in the direction opposite of flows to NL) which enables an additional profitable trade of 150x100-150x80 = +3000€ from BE to NL (which thus more than compensates the welfare-losing trade).

In a nutshell, a non-intuitive flow is the consequence of some sort of “trade-off” that can non-intuitively set “welfare loosing trades” on some exchanges if they enable further “welfare generating trades” on other exchanges which more than compensate the losses, and is intrinsically linked to the fact that all trades don’t have the same impact over the constraints (i.e. flow factor competition weights the “loosing trades” and the “winning trades” based on their relative impacts over the constraints).

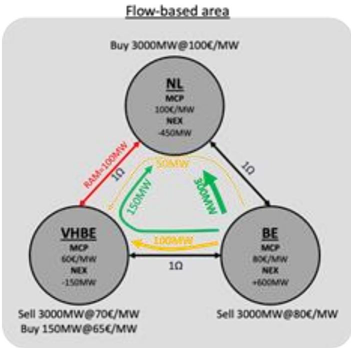

Figure 78 : VHBE imports while being the cheapest market, which frees up capacity enabling further welfare creation

4.6.2.1 Non-intuitive example specific to AHC with a hybrid interconnector

The previous examples were not directly related to AHC and were an introduction to the notion of flow based pricing and non-intuitivity. In this section the aspect of an OBZ with AHC is added.

Expanding on the previous example, let us consider the topology and orders as shown in Figure 4, which schematically represents the Princess Elisabeth Zone as an Offshore Bidding Zone (OBZ) fed by wind generation. It is connected on the one hand to Great-Britain (GB) and on the other hand to our simplified flow-based area composed by one virtual hub in Belgium, one real hub in Belgium and a third real hub representing the Netherlands. In reality, the flow-based will likely be the CORE flow-based region at that time, but this simplified topology illustrates the conceptual principles sufficiently well while limiting the complexity of the example.

In addition, a value for the capacity of the ATC lines between VHBE and OBZ and GB and OBZ is needed. Without making any assumptions on the real ATCs, 1200MWh for the VHBE-OBZ and 900 MWh for the OBZ-GB is used in this example for illustrative purposes.

Lastly, VHBE has no orders (which will also be the case in reality in the market coupling where virtual hubs are indeed only there to facilitate the implementation of AHC, but where no real orders will be submitted), and the GB orderbooks are assumed to be 3000 MWh of offer at 70 €/MWh and 3000 MWh of demand at 60 €/MWh. The offshore windfarm in the OBZ expects to produce 750 MWh of wind production and offers this wind production at a price of 0 €/MWh to the market. NL and BE orderbooks remain as in the previous example.

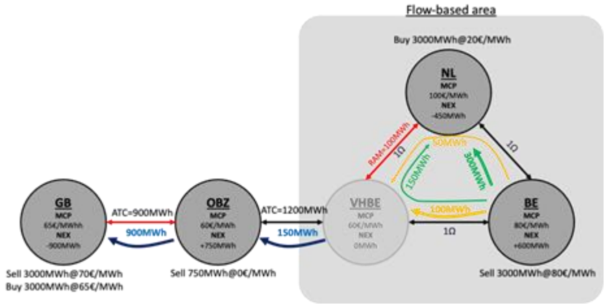

Figure 79 : If the VHBE price is not visible, BE seems to (non-intuitively) export to OBZ

With these data, NL imports 450MWh and clears at 100€/MWh, BE exports 600 MWh and clears at 80€/MWh; and VHBE import 150MWh in the flow-based area and clears at 60€/MWh due to the FB pricing principles, again including a non-intuitive flow between BE and VHBE for the reasons as explained in the previous examples. On the flow-based domain, a net flow of (⅓.600 - ⅔.150) = 100MWh on the tie line is constraining further trade within the region. But also further trade on the external borders is hereby prevented, since the concept of AHC allows the market coupling algorithm to create efficient competition between internal and external borders for the usage of scarce capacity.

This example is similar to the one above with the key difference that VHBE has no order and instead re-exports its net position to the OBZ (which in turn, together with the wind, exports it further to GB). Because there is no flow factor competition in ATC constraints, their price properties (i.e. dual optimality conditions) are always intuitive: the flows over ATC lines always follow the price difference from low to high price areas; and a price difference is only possible when the ATC constraint is binding/congested[21]. As VHBE exports 150MWh to OBZ, the ATC is not congested and the OBZ clearing price must be the same price as in VHBE, e.g., OBZ clears at 60€/MWh. At this price the offered wind production is fully in the money hence its volume of 750 MWh is fully accepted. As a consequence, the OBZ exports a total of 900MWh (750 MWh wind + 150 MWh export of the VHBE) to GB over a congested ATC line, and GB thus imports 900MWh and clears at 65€/MWh (the price of the marginal buy order).

In terms of intuitiveness, one should remind that VHBE is a “virtual hub” and therefore its price is not typically looked at when looking at market prices across the market coupling areas (it is more common to look at prices associated to real bidding zones). However, without considering the price of VHBE, it then appears that BE clears at 80€/MWh, and that Belgium exports (in practice through its virtual hub) to OBZ

[21] *In our simplified examples, we ignore losses and ramping constraints – which would otherwise impact these properties.*

which clears at a lower price of 60€/MWh. The OBZ price is thus not contained within the bounds of prices of the (non-virtual) flow-based areas. The OBZ intuitively exports to the more expensive GB that clears at 65€/MWh.

The main take-aways of this is example are twofold:

1. The OBZ will be connected to its neighboring hubs via ATC constraints and the flows over ATC lines always follow the price difference from low to high price areas and a price difference is only possible when the ATC constraint itself is binding/congested (apart from ramping or losses)
2. When not considering the prices of the virtual hubs which are connected to the OBZ, it might appear that the OBZ prices are behaving illogically and not intuitive when only comparing “real hubs” (in this case GB and BE). Hence for correctly understanding the pricing behavior of the OBZ the virtual hub price must explicitly be considered.

4.6.2.2 Virtual hubs are essential to understanding pricing behaviour of OBZ under Advanced Hybrid Coupling

In a nutshell, the non-intuitiveness inherent to flow-based market coupling is further underscored by AHC if some prices (e.g. the prices of the virtual hubs) not considered because they are less visible (e.g. because they do not apply to actual trades). If the prices of the VH are not considered by traders.

In general, it is NOT possible to identify any strong/robust “price property” that applies to AHC if the VH prices are ignored/hidden. On the contrary, if VH prices are considered and visible, the prices within the FB area respect the regular “FB pricing properties” (which may be non-intuitive but are fully justified), and the prices over ATC lines respect the regular “ATC pricing properties” (which are genuinely intuitive, despite the caveats related to ramping or losses). Therefore, in case of a 1-sided AHC model where the OBZ will be connected to only 1 virtual hub, at least one of the two ATC lines connecting an OBZ will be intuitive when comparing its prices to the adjacent real bidding zone (but of course intuitive to on both ATC interconnectors when also considering the virtual hub). On the contrary, in case of a multi-sided AHC model (e.g., an OBZ connecting to BE in the flow-based CORE area, directly to another bidding zone with AHC and flow-based Hansa/Nordic area or even possibly with GB in a nodal setup), the OBZ will then be connected to two virtual hubs. Hence the price properties between the OBZ and their connected “real-virtual hubs” follows no analytical rule, justifying the need to also consider the prices of both virtual hubs for properly understanding its behavior.

4.6.2.3 Volume effects on the OWF due to competition with the FB grid

Given the above, it is very easy to create any desired illustrative example. Figure 73 is the same as the example of Figure 72 but where the sell order in BE is now less expensive and becomes priced at 40€/MWh. Following the same reasoning as above, it remains welfare profitable to accept that order as much as possible so that it becomes (partially) accepted. Consequently, the price in BE is now 40€/MWh and, because of the Flow Based pricing principles, the price in VHBE is -20€/MWh (minus twenty €/MWh) as the price difference between VHBE and NL must be the double of the price difference between BE and NL.

When VHBE imports 1MW from BE at 40€/MWh and re-exports this energy to OBZ, which in turn exports it to GB where, it is sold at 65€/MWh in GB. This trade from BE to GB thus generates a welfare of 45€. In addition, it relieves the flow-based constraint such that BE can export an additional 1MW to NL which generates an additional welfare of 100-40=60€. As a result, the optimal solution consists of BE exporting 2100MWh; NL importing 1200MWh and GB importing 900MWh which is fully delivered by the BE hub and not by accepting any wind production.

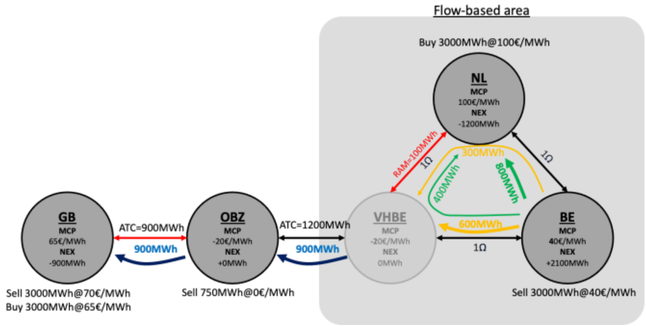

Figure 80 : Non-intuitive example where the cheapest order in OBZ is optimally rejected due to a virtual price

As explained before, if the price/role of the Virtual Hub in this result is not taken into account, a wrong conclusion would be that BE clears at 40€/MWh while Belgium fully exports to GB which clears at a higher price, and while the cheap (wind) offered in OBZ is rejected. To justify why this is optimal, let us start with the optimal solution and suppose that we impose to accept 1 MWh of the cheap sell order of wind in OBZ.

This may appear as profitable at the first look, because we substitute a supply of 40€/MWh in BE with a supply at 0€/MWh in OBZ, hence generating an additional welfare of 40€. However, doing so implies that NL must import 1MWh less from BE to respect the flow-based constraint, and hence 100-40=60€ of welfare is no longer generated.

The net effect of imposing to accept 1MWh of the order in OBZ is thus 40-60=-20€ of welfare (which is by construction the price applicable to OBZ). On the contrary, if the supply in OBZ would have been priced at -20€/MWh, enforcing its acceptance would have a neutral effect, while it would be welfare optimal to accept the supply in OBZ if it is priced strictly below -20€/MWh. This is precisely why OBZ clears at -20€/MWh, which signals that a sell order priced below this limit would be "in the money" and accepted. As a conclusion, optimal results under AHC can only be justified by taking into account the prices of the virtual hubs and the "non-intuitive" effects implied by flow-based market coupling.

4.6.2.4 Volume effects on the OWF due to negative prices

The following example in Figure 74 further builds on the data in Figure 5 where the GB demand is reduced, and the GB supply becomes priced negatively at -30€/MWh. GB now offers very cheap energy, which changes the direction of the flow such that GB exports 150MWh to NL. The fractionally accepted supply in GB sets the clearing price of GB to -30€, as well as the prices of OBZ and VHBE which are part of the same uncongested flow over the ATC lines between GB-OBZ and OBZ-VHBE. In the flow-based area, the constraint is saturated, and the importing NL clears at 100€/MWh. Due to the flow-based pricing properties, BE clears at 35€/MWh. It is to note that supply in OBZ and in BE are rejected as they are out of the money, following the same reasoning as described above.

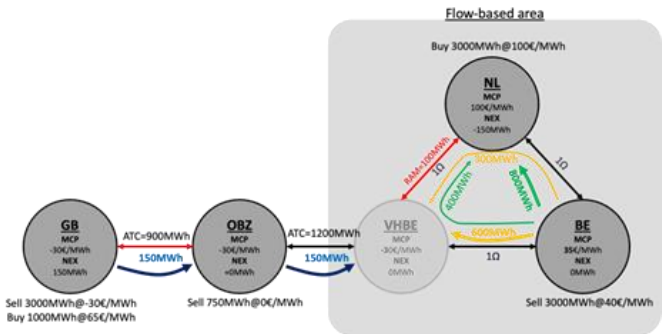

Figure 81 : Volume risk for OWF due to negative prices in GB

5. Balancing design

5.1. Executive summary

In 2020, Elia published its “MOG 2 system integration” study which formulated recommendations for the system integration of 2.1GW of additional offshore wind capacity by 2028, being the Belgian ambitions at that time. The study already concluded that specific mitigation measures were needed to manage the integration of additional offshore wind power, on top of the currently 2.3 GW installed.

The renewed offshore ambitions communicated at the end of 2022 by the government, aiming to install between 3.15 and 3.5 GW of additional offshore wind power capacity by 2030 in the Princess Elisabeth Zone requires a careful analysis to conclude if the proposed mitigation measures are sufficient in a system with now up to 5.8 GW of offshore wind power.

As in previous studies, it has to be investigated if the system can cope with the expected and unexpected variations of wind power, as well as exceptional balancing conditions which will be caused by storm and ramping events:

- storm events concern sudden variations of wind power generation due to the shutdown (cut-off) and re-activation (cut-in) behavior of wind turbines in case of elevated wind speed (above 20 m/sec) related to high wind speed management systems of turbines;
- ramping events concern sudden variations of wind power generation as a result of wind speed variation related to the exponential profile of the power curve at normal wind speeds (below 20 m/sec).

Being responsible for secure system operations, it is important for Elia to investigate the potential impact of such behavior on the system security and make the necessary preparations to implement adequate technical capabilities and appropriate procedures to cope with these phenomena. As some of these technical capabilities will need to be ensured via the wind turbine and wind farms to be installed, it is important to specify the required capabilities before the first wind farm concession is tendered in 2024.

In a first step, Elia updated its projections of balancing reserve requirements following the integration of additional offshore wind power, and variable renewable generation in general. The results confirm the increasing of upward FRR reserve capacity needs from around 1000 MW today, towards 1590 MW in 2030 in the CENTRAL scenario, e.g. Elia’s best estimate based on the last Adequacy and Flexibility 2024-34

study published by Elia. Scenarios with low flexibility in the system may increase these FRR needs to almost 2000 MW in 2030, while most ambitious scenarios in term of flexibility developments allow to limit these needs to around 1300 MW.
Note that Elia's has the ambition to manage increasing reserve capacity needs without additional balancing capacity procurements through the implementation of its dynamic procurement, which is forecasting available local and cross-border non-contracted balancing energy bids in the system for the next day to procure only upfront the missing energy as balancing capacity. This will nevertheless require substantial efforts in the development and participation of new flexibility in the system, either with reactive balancing through BRP portfolios or with balancing energy bids.

Elia does not expect a fundamental impact of creating an offshore bidding zone on reserve dimensioning and balancing capacity procurement. While reserve capacity needs may slightly increase due to lower reactive balancing opportunities for the Balance Responsible Parties (BRPs) in the offshore Load Frequency Control (LFC) Area, the flexibility that would have been used for portfolio balancing by the BRPs should become available through balancing energy bids in the EU balancing platforms. This will be accounted for in the dynamic procurement to reduce the need to procure balancing capacity. Network constraints between the Princess Elisabeth Island (PEI) and the Belgian onshore system are neither expected to play a major role in the dimensioning of reserves as access of upward balancing energy is always available via the connection to the onshore network, while the availability of downward balancing energy bids is guaranteed through downward flexibility of wind power.

In a second step, Elia conducted system simulations of real-time operations with additional offshore wind power. The simulations are built on simulated offshore wind power generation profiles towards 2030, based on the latest assumptions of the future offshore generation park, discussed with stakeholders in the Task Force Princess Elisabeth Zone (PEZ). The study also takes into account latest projections on system flexibility and balancing market performance.

The system simulations predict frequent and large system violations under 'worst case' balancing market conditions and conclude that mitigation measures are needed to cope with:

- downward ramping events (resulting in system shortages), during storm conditions which may result in a fast cut-off of the wind generation to protect the installations from very high wind speeds, as well as during fast reductions of wind speeds under other conditions;
- upward ramping events (resulting in system excess), during storm conditions resulting in a fast re-activation of the wind generation when wind speeds decrease, as well as during fast increase of wind speeds under other conditions.

Note that in the analyses presented in this report, Elia also assumes that market participants shall be responsible for the imbalances they cause in the system. This balancing responsibility translates in the incentive to minimize portfolio and system imbalances.

In addition, the study takes into account new expected developments concerning the offshore grid topology presented in Section 0. This topology may evolve from a simple hybrid interconnector connecting the offshore wind power and two countries, to an energy island serving as a hub in a meshed HVDC grid. Concerning the impact on the balancing market, Elia studied the impact on the LFC block structure when an offshore bidding zone is implemented. The option to have one LFC block with two LFC areas is retained as the most efficient.

Elia has a constant focus to facilitate the participation of new flexibility in the market and to increase the possibilities of market parties to balance their portfolio. This is expected to contribute to a more efficient and balanced system. Nevertheless, balancing market performances are subject to uncertainty and a worst case outcome remains a possible trajectory towards 2030, certainly if barriers for the participation of new and decentral flexibility are not timely removed. This includes the need for market reform (to allow this flexibility to actively participate in the market and to react on price signals). The uncertainty regarding whether sufficient flexibility will be in the market requires mitigation measures which can act as safety net under low balancing market performance. However, if the market evolves towards good performance, the mitigation measures will not be effectively used, or at least under rare circumstances.

The study is built on several interactions with stakeholders on the method, assumptions, results, and conclusions following several presentations and workshops in the Task Force PEZ. After the public consultation, Elia will conclude on the implementation of the mitigation measures for storms and ramping events and determine the tender specifications accordingly.

MITIGATION MEASURES

Elia confirms the need for the three main mitigation measures for storm and ramping events presented in the original MOG 2 system integration study:

1. High Wind Speed capabilities

Turbines with **High Wind Speed capabilities** allow wind turbines or wind farms to maintain generation under very high wind speed conditions associated to storms while demonstrating a gradual ramp down of the generation. Elia demonstrates that this capability allows to substantially reduce the occurrence and the impact of sudden wind power cut-offs during storm conditions.

This technology, already demonstrated in existing wind farms, is expected to become a standard feature. Imposing this feature on newly installed offshore wind turbines is considered to be a no-regret solution. Once installed, no further operational procedures are needed as the wind park ought to have the financial incentives to continue generation under the highest wind speeds possible when facing adequate market prices.

2. Ramp Rate Limitations

Ramping rate limitation on wind farms are shown to maintain system security during fast and large upward ramping events, resulting in unexpected excess energy in the system, both during low wind speed conditions (during a fast increase in wind speeds) and storm conditions (a re-activation after a storm cut-off).

While the frequency and the impact of the latter should already be reduced with the High Wind Speed capabilities, it is shown by Elia that a ramp rate limitation is indispensable to manage excess generation. The ramp rate limitation requires new farms to limit their upward ramp by reacting to a close-to-real-time signal sent by Elia when the system faces large excess of energy (represented by the LFC block imbalance). Note that today, the re-activation after storms is also coordinated bilaterally between each park and Elia. With the additional 3.5 GW to be installed, a “park by park” coordination cannot be sustained from an operational point of view. Note that existing wind farms will be allowed to choose between either keeping today’s cut-in coordination regime[22] or switching to the ramp rate limitation regime.

It is important to note that as long as the LFC block imbalance remains under a reasonable threshold, e.g., remaining under a positive instantaneous LFC block imbalance of 500 MW, the farms remain free to inject their available power without any intervention from Elia. This means that the market maintains all means to balance their portfolio and avoid the activation of the ramp rate limitation by Elia. If the ramp rate limitation must nevertheless be activated by Elia during a large system excess, the imbalance price is typically low and might even be negative. During such conditions, the financial impact of losing the positive imbalance revenues remain limited and can even be to the advantage of the wind park.

3. Preventive curtailment

Preventive curtailment foresees, in last instance, to communicate to curtail part of the wind power in the intraday timeframe to anticipate an expected system shortage following downward ramping events. The mechanism is needed on top of the High Wind Speed capabilities to deal with the downward ramping events caused by the cut-off during storms, as well as with the fast downward ramping events during rap-

[22] In order to cope with an increasing amount of parks to manage, Elia foresees to automize the cut-in coordination procedure towards the commissioning of the first new offshore parks.

idly declining wind speed conditions. The measure needs to mitigate the risk of a short LFC block imbalance, as it requires market players to cover the curtailed wind energy by means of additional intraday market trades. This will then avoid wind power shortages occurring in the balancing timeframe.

Like in the current storm procedure, BRPs need to first inform Elia about the measures that they plan to take in prevision of a forecasted storm event. Only when those measures, and the expected reserves at disposal of Elia, would not be sufficient to cover the impact of the storm, Elia would request a downward curtailment on the wind farms. The curtailed volume will be in function of the remaining shortage to be managed. Note that Elia will have activated the slow start units first in line with its current storm procedure. This means that the measure will only be triggered after giving the market the opportunity to self-balance, and after all expected balancing means of Elia are used. If applied, the financial implications of the curtailment are expected to be limited to the spread between the intraday market price and the imbalance price, and can therefore even be positive, at least if correctly predicted.

An important caveat is that the predictability of downward ramping events during low wind speed conditions is not as high as with storm events. While over-forecasting will result in costs for the market parties, under-forecasting will result in system security violations requiring alternative measures, such as for instance the increase in balancing capacity requirements. Elia is investigating the future predictability of the ramping events.

Figure 82 presents an overview of the mitigation measures for storms and ramping events. These are a safety net for Elia to ensure system security under low balancing market performance conditions and the required wind turbine or wind park technical capabilities are therefore to be ensured via the tender requirements.

Elia believes that the mitigation measures are proportionate in view of alternative solutions based on procuring additional reserve capacity and is therefore fair in view of the allocation of the costs to the responsible parties:

- The mitigation measures are designed to give to BRPs all opportunities to self-manage the expected impact of storm and ramping events in the intraday, and even up to the balancing timeframe;
- No costs are incurred when the market shows good performance by triggering activation in intraday or balancing timeframe.

Elia aims to provide as much visibility and transparency as possible in this report by presenting the design principles to market parties. Nevertheless, while the technical capabilities to deliver the mitigation measures will be imposed by Elia through the connection requirements linked to the tenders for offshore wind concessions, the operational procedures themselves are subject to regulatory approval and might also be subject to system evolutions towards 2029 - 2030.

		Definition	Justification	Implementation*	Activation
Storm and Ramps	High wind speed technologies	Technical minimum requirements on new wind turbines of wind parks to maintain generation during high wind speeds	Reduce frequency and impact of shortage power following storm cut-off wind speeds Technology capabilities exist already today and are assessed to become a standard technology	Technical specifications on turbines or at park level are specified via connection requirements to continue generation until 31 m/sec after a gradual power decrease	Technical capability is assumed to used by market players to limit impact of storm events on wind power injections
Storm and Ramps	Ramp rate limitations	Real-time limitation of the upward ramp rate of new parks (and existing parks on voluntary basis) during elevated positive imbalances in the LFC block	Mitigate frequency and impact of excess power following increasing wind speed conditions or re-activations after a storm Simple, automatic and transparent procedure compared to the manual cut-in coordination of existing parks	Control requirements are specified via connection requirements Operational procedure will be implemented via LFC block operational agreement and T&C for Scheduling Agents	Automatic trigger communicated by Elia after market reaction and limited to periods of large positive LFC block imbalances No trigger is expected in high balancing market performance scenarios
Storm and Ramps	Preventive curtailment	Intra-day communication of wind power curtailment of new parks following predicted storm event or downward ramping event to reduce expected LFC block imbalances	Mitigate frequency and impact of shortage power following storm cut-off wind speeds.	No specific technical requirements needed Operational procedure will be implemented via LFC block operational agreement and T&C for BRPs	Trigger by Elia only as last resort after a storm or ramp forecast, insufficient market reaction and insufficient flexibility in reserves No trigger is expected in high balancing market performance scenarios
Hybrid IC	Preventive cap	Real-time limitation of the excess wind power injection of new wind parks following remaining network capacity in the balancing time frame	Maintain system stability in hybrid HVDC system during high import conditions to Belgium as complement and back up for balancing agreements with connected region	Control requirements are specified via connection requirements Operational procedure will be implemented via Capacity Calculation processes and local congestion management framework (ICAROS)	Continuous cap limiting positive imbalances in function of available network capacity. Impact is limited to high import conditions to Belgium and further limited when disposing of balancing agreements with connected regions.

*Technical specifications in connection requirements will be defined during tendering phase in 2024, proposals of the modifications to the regulatory framework are foreseen around 2027

Figure 82 : Overview of mitigation measures

Figure 82 presents a fourth mitigation measures in light of the expected offshore grid topology, based on the hybrid HVDC interconnector connecting the offshore wind power with Belgium and the United Kingdom. Elia identifies a need for a fourth mitigation measure, referred to as the preventive cap.

4. Preventive cap

The preventive cap serves to prevent in real-time network constraints caused by unexpected excess of wind power. It is demonstrated that in a case where the import to Belgium (following import from the connected region, in first instance UK and later Denmark, together with the offshore wind power generation) reaches the limits of the HVDC system, excess wind power after the intraday timeframe needs to be capped to maintain system security. During such conditions, this excess wind power cannot be evacuated to the Belgian LFC area to avoid overloading the HVDC system.

This means that in order to maintain a safe operation of the HVDC system, a preventive cap will need to be imposed on the wind parks. The preventive cap is thus a specific measure needed for managing the hybrid use of an of HVDC system and will apply irrespectively of the market setup. It will come on top of the general local congestion management framework to cover congestions in the AC system.

This preventive cap corresponds to a real-time injection limit which will be calculated based on the available capacity in the HVDC system.

To avoid that the trigger for such real-time injection limits would come unexpected, the wind farms need to have a foresight on the expected value on this injection limit, or the operating margin in which they can inject their excess wind generation.

This information is an inherent part of the limitations considered in implicit trading with an offshore bidding zone, where capacity calculation will reflect the direction in which capacity is available. In case it is not possible to implement an offshore bidding zone (cf. Section 0), a home market setup will be in place. Elia intends to mimic similar congestion management approach. A best estimate of this injection limit (determined as an operating margin for the wind farms) will be communicated in intraday to allow the wind farms to determine the additional injections which can be supported by the system. This will require to take into account the capacity of the HVDC system, the cross-border exchanges in the day-ahead, intraday and balancing market, the capacity traded explicitly with UK, and the generation schedules within the Princess Elisabeth Zone. Schedule updates that would go beyond the operating margins of the HVDC system will not be accepted.

Note that in most of the situations, it remains possible to trade excess energy in at least one direction. For example, when the preventive cap will be triggered following export constraints towards Belgium, exporting towards UK remains typically possible. Further balancing opportunities to exchange very fast imbalances with the connected regions may mitigate or limit the activation of the measure by allowing to export the excess to, for instance, the United Kingdom or Denmark. Also, the availability of balancing cooperation for slower flexibility may limit the duration of the trigger allowing to ensure the export of the excess energy in the aFRR or mFRR timeframe. While such balancing cooperations are currently already existing with Denmark, this is not the case with the United Kingdom.

It is found that, under the selected subsidy mechanisms (a capability-based contract-for-difference complemented with the possibility of power purchasing agreement), no financial compensation nor limit on the amount of activation of the mitigation measures are recommended. This because firstly, the effect of the mitigation measures on the business case of the wind farms is expected to remain limited. Secondly, Elia considers that allocating the costs to the market players responsible for the system security risk and the activation of the mitigation measure is fair. Thirdly, it maintains the right incentives to balance to the market parties.

Finally, Elia investigated the potential impact of an offshore bidding zone on the mitigation measures. It concluded that there are no fundamental impacts and the mitigation measures can be considered robust for a framework with an offshore bidding zone, as well in a home market solution. Nevertheless, while the offshore bidding zone improves adequate price signals in the balancing timeframe, there might be a slight increase on the activation frequency and an impact on the trigger design, at least for the mitigation measures covering storm and ramping events.

IMPLEMENTATION ROADMAP

Via this study, Elia recommends the implementation of three specific mitigation measures to manage the future impact of offshore storms and ramping events on system security, and one additional mitigation measure to manage excess wind power in a hybrid interconnector.

To allow Elia to manage system security, also in situations with limited balancing market performance, the High Wind Speed, Ramping Rate Limitation and Preventive Cap capabilities are to be specified in the Tender requirements (Section 5.9). By enforcing these capabilities as additional requirements in the connection requirements, Elia enables the possibility to implement the mitigation measures to ensure system security, particularly when connecting the full offshore capacity in the Princess Elisabeth Zone to the system in 2030. Note that the Preventive Curtailment does not impact the connection requirements as these capabilities are already foreseen through general connection requirements.

Additionally, the operational procedures to implement the ramp rate limitations, preventive curtailment and preventive cap need to be implemented through the regulatory framework in line with legal requirements. Elia foresees to draft, consult and submit for approval the proposals towards the commissioning of the farms. This still ensures sufficient time for implementation of the operational procedures and required applications before the commissioning of the first wind farms. Submitting the proposals earlier in time is not deemed appropriate in view of adapting the proposals to the latest system evolutions.

Meanwhile, Elia will continue its effort to ensure the participation of new flexibility in the market, and thereby the ability of market players to balance their portfolio. Good balancing market performance will allow to limit (and maybe even avoid) the triggering of the mechanisms and therefore also the financial impact on the system.

5.2. Introduction

5.2.1. Context

Previous studies such as Elia's offshore integration study published in 2018 and the MOG 2 system integration study published in 2020, as well as the experience with the current offshore generation fleet of 2.3 GW as from 2020, have demonstrated the impact of unexpected variations of offshore wind power generation on the system imbalance in the Belgian control zone, also referred to as the Belgian LFC block. Particularly the unpredicted variations during high wind speed conditions (hereafter also defined as "storm events") or sudden changes in wind speeds or wind direction (hereafter also defined as "ramping events") have shown to trigger substantial system imbalances in the Belgian control area. This issue is particularly relevant for the Belgian system as all Belgian offshore wind farms are situated close to each other in the North Sea while it has been observed that they all behave in a similar way facing a storm or ramping event.

In 2018, Elia has published **a first study on offshore wind power integration** aiming to prepare for the commissioning of the first wave of 2.3 GW by 2020. It raised awareness on potential power variations of storms and ramps facing limited predictability and formulated several recommendations which were put into practice to manage storm events such as the development of (1) storm forecasting tools, (2) a procedure triggering specific coordination between Elia and the involved market parties upon identification of a storm (storm procedure) combined with fallback measures to pro-actively create additional flexibility in the system (exhausted reserve procedure), and (3) additional financial incentives for market parties to balance wind power generation during extreme conditions (alpha parameter).

In 2020, Elia has published the **MOG 2 system integration study** which formulated recommendations for the system integration of offshore wind capacity up to 4.4 GW. The study included several workshops with stakeholders and public consultation of the report. The study recommended a set of operational and technical constraints for the wind farms or concerned market players (BRPs) which need to be specified before the tender for additional offshore wind power capacity, including the implementation of high wind speed technologies, ramping rate limitations and preventive curtailment measures. In addition, it recommended a set of general actions to be investigated by Elia such as further incentivizing appropriate reactions of BRPs, enhanced mFRR activations strategies and enhanced forecast functionalities.

While the general actions were included in Elia's different development roadmaps, the operational and technical constraints were, on request of stakeholders, subject of an update of the study following the commissioning of the full 2.3 GW. The scope, objectives and planning of this study were validated in a workshop with stakeholders on June 28, 2021 but the study was thereafter put on hold following new offshore developments communicated by the government. In 2022, Elia re-launched this update of the study including an investigation of:

- **the impact of increasing offshore wind capacity from 4.4 GW to 5.8 GW** on real-time balancing, reserve needs and proposed mitigations measures;
- **the impact of the offshore grid topology** based on hybrid HVDC interconnectors connected to a meshed HVDC grid including an offshore energy island named the Princess Elisabeth Island, as well as the potential **implementation of an offshore bidding zone** impacting the operation of the Elia's LFC block and imbalance price area.

5.2.2. Scope and objectives of the study

Figure 83Figure summarizes how the balancing study has been structured into four blocks. The first block contains an update of the simulations of future offshore generation and prediction profiles, as well during normal conditions as during extreme wind power conditions defined by storm and ramping events.

In the framework of the MOG 2 system integration study (2020), the Technical University of Denmark (DTU) validated a model on historical observations and implemented it to simulate future offshore wind power generation and prediction profiles for 2.3 GW, 3.0 GW and 4.0 / 4.4 GW for the Belgian offshore zone. In the framework of the study presented in this document, DTU validated and used its model based on latest meteorological data (up to the end of 2021), the latest generation data of the full 2.3 GW offshore fleet installed, the new commissioning calendar (5.8 GW by 2030) and an update of technology assumptions (towards 2029 - 2030). The simulated generation profiles during storm and ramp events are used in the real-time system operation simulations for ramps and storms while the generation and prediction time series are used for the reserve capacity projections. A summary of the analysis is presented in Section 5.4, while the full DTU report is made available in Appendix 6.

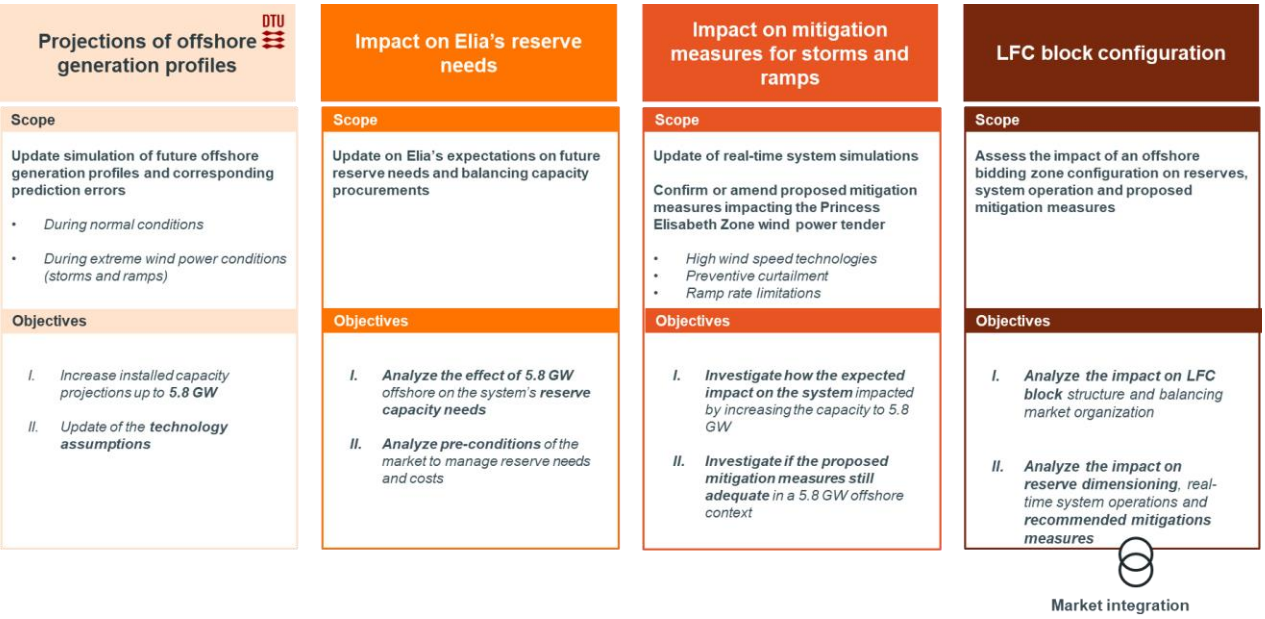

Figure 83 : Structure of the study

The second block contains an analysis of the impact of Belgium's renewable ambitions on Elia's reserve needs. On regular basis, Elia publishes projections of its reserve capacity needs. Projections until 2028 were published in the MOG 2 study (2020) with a presentation of reserve needs evolutions under best, worst and reference scenarios. These projections were recently updated in Elia's Adequacy and Flexibility study of 2023. The results presented in Section 5.5 of this report are based on the results published in this study with projections based on latest system observations (system imbalances and forecast quality) while taking into account the expected system evolutions.

Note that the results do not directly impact the tender specifications for the Princess Elisabeth Zone as such but impact the real time system operations and costs, and this exercise should also be seen in the framework of the request of stakeholders towards market stability and visibility on future evolutions. The available reserve capacity is also an important assumption in the system simulations of real time operations presented in Section 5.6 and indirectly impact the justification of the mitigation measures needed to manage storm and ramping events.

It is important to stress that reserve projections are only indicative as real reserve capacity needs and balancing capacity procurements will be determined on daily basis by the methodologies approved in LFC block operational agreement and LFC Means, approved by CREG after public consultation. In addition, the results of the projections are used as assumptions on the minimum available flexibility during storm and ramping events and therefore impact the need for mitigation measures impacting the tender requirements.

The third block presented in Section 5.6 aims to update the simulations on real time system operation during storm and ramping events with latest observations on such events, expected system evolutions and the updated projections of generation and forecast profiles delivered by DTU. It needs to re-confirm the need for the recommended mitigation measures and further elaborate on their implementation as specified in Section 5.7 of this report. Note that while the initial focus of the study was on confirming the mitigation measures, a context of 5.8 GW raises the question about the need for complementing and fortifying the proposed mitigation measures. The study aimed to be robust towards new evolutions compared to the 2020 study. The model has been improved and adapted to the latest system evolutions, while market performance criteria have been revised in view of the latest observations.

The fourth block aims at identifying the potential impact of creating an offshore bidding zone to which the new wind power will be connected on the balancing market as well as on the conclusions of the other blocks (on reserve dimensioning, system operation and mitigation measures). It is to be noted that the implementation of such offshore bidding zone is under discussion (Section 4.5). Elia also stresses the novelty and complexity of the topic, with no best practices, limited literature and a legal framework which was never conceived for such a context. The analyses presented in this chapter are based on the discussions of dedicated workshops on this subject with stakeholders. This block presented in Section 5.8 should therefore be seen as an extension of the analyses presented in discussion on market design of an offshore bidding zone.

Section 5.9. concludes this chapter on balancing with an overview of the implementation roadmap of the recommended mitigation measures presented in Section 5.9.

5.2.3. Timeline of the study

Figure 84 shows the timeline of the study showing the extensive stakeholders interaction track. Firstly, effort was put in aligning the assumptions of the study. This is important considering the vast amount of simulations and analyses and the difficulty to revise fundamental assumptions during the process. Secondly, attention was put in presenting the full results of the analyses to stakeholders. Stakeholders could raise questions during the presentations, as well as after the presentations in a bilateral way. Elia answered in the Task Force to ensure full dissemination of available information. Finally, stakeholders have now the opportunity to raise their questions and remarks in a formal context during this public consultation.

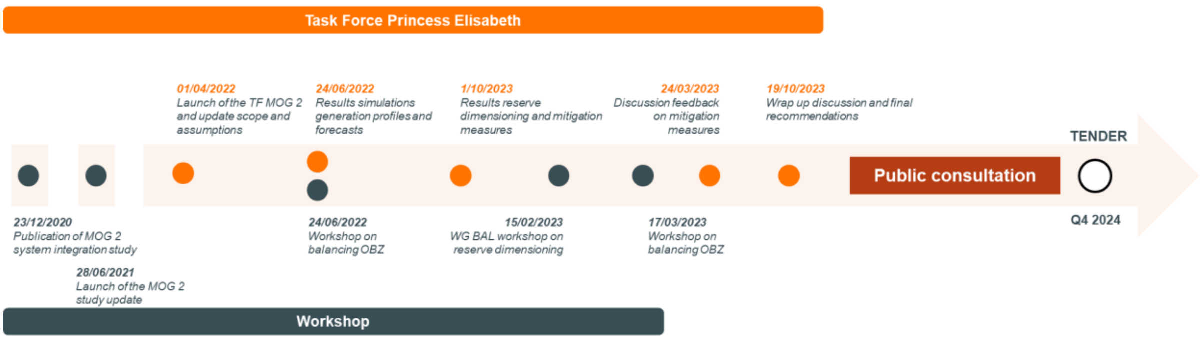

Figure 84 : General planning of the balancing study

5.3. General assumptions

The generation and forecast profile simulations conducted by DTU were launched in April 2022. Assumptions were presented to stakeholders in the Task Force PEZ of April 1, 2022. Stakeholders were requested to provide input which might improve the accuracy of calculations. Such input was needed to be received before April 22, the latest.

Inputs were received from turbine manufacturers, the Belgian Offshore Platform and Public Services which resulted in a communication of the updated assumptions by mail on April 29, 2022.

5.3.1. Installed wind power capacity

The wind generation and prediction profiles were conducted for different scenarios. Firstly, simulations are conducted for the existing Belgian 2018 fleet (0.9 GW) and the Belgian 2020 fleet (2.3 GW). These simulations are only used for model validation as the results of the simulation can be compared with the observations. Note that the Belgian 2018 scenario corresponds with the MOG 2 study in 2020 and is kept in this study to allow comparison between both studies but the focus of this report is on the validation of the Belgian 2020 fleet.

Secondly, projections of wind power generation and forecasts are simulated by DTU for 3.0 GW (initially foreseen for 2028), 4.4 GW (initially foreseen for 2029) and 5.8 GW (foreseen for 2030). Begin 2023, during the Task Force PEZ of January 10, 2023, the Federal Government communicated an update of the planning in which it is specified that 3.0 GW will only be realized in 2029, while the full 5.8 GW remains foreseen for 2030. This does not directly impact the analyses conducted by DTU but the 4.4 GW scenario loses relevance for the study. However:

- Focus of the system simulations in Section 5.6 to investigate the impact of extreme balancing conditions were focusing only 5.8 GW and therefore the update of the planning has no impact on the results presented in this study;
- While the impact on reserve capacity simulations was presented in the Task Force PEZ on January 10, 2023 with the old planning. This new planning impacts the calculations for 2028 and 2029. The simulations are for this reason updated in this report with latest renewable projections presented in Elia's Adequacy and Flexibility study 2023.

It is noted that the official communications of the Federal Government target an additional installed capacity of 3.15 – 3.5 GW[23] but in order to assess robust criteria for the tender, the maximum targeted capacity is taken as reference in this study.

5.3.2. Topology

Figure 85 represents the topology (location of the wind turbines) assumed in the study. Note that as with the previous study, the Borssele offshore cluster in the Netherlands is considered because large wake effects are expected due to its proximity to the Belgian fleet. The planned offshore plants in Dunkirk

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[23] *More info on FPS Economy website: https://economie.fgov.be/en/themes/energy/belgian-offshore-wind-energy*

France are not modelled because their larger distance to the Belgium fleet makes them irrelevant in terms of farm-to-farm wake losses.

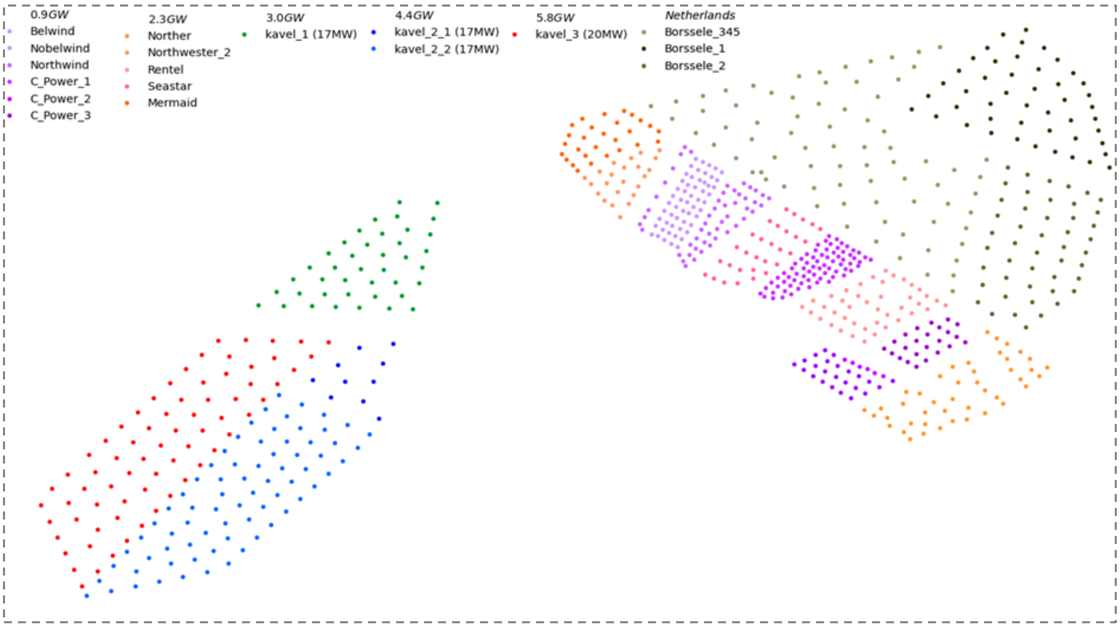


Figure 85 : Plant and turbine locations relevant for the different stages of offshore wind installations

Elia assumed at the start of the simulation a fixed density on the foreseen geographical area (Princess Elisabeth zone). Last available information on the location of the electric equipment are taken into ac-count (location island and corridors for cables) as presented on the website of the FPS Economy in April 2022.

At this point, the potential impact of gravel beds (excluding part of the zone for construction for ecologic rea-sons) is not included as there was at the start of the analysis (and still not at this moment) no cer-tainty on the exact surfaces to be excluded (and the potential impact on the offshore capacity installed and generation). While there is likely an impact on the capacity factor and the wind power yield, the im-pact on the system integration simulations (forecast errors, storms and ramps) is expected to be limited.

The several stages of the installations of the Belgium offshore wind power fleet considered in the present study are shown in Figure 86, coming in addition to the full MOG I fleet (the 2.3 GW case). The 3.0 GW scenario includes the addition of the Kavel 1 area, the 4.4 GW scenario also includes the Kavel 2 areas, and the final 5.8 GW scenarios also includes the Kavel 3 area.

It should be noted that the scenarios up to 4.4 GW are not identical to the 2020 report (even though the names are similar), as they do not consider the same geographical areas: e.g., the 4.4 GW scenario pre-sented in this study uses much less space than the 4.4 GW scenario presented in the 2020 report (where the entirety of the Kavel 1-3 areas was assigned to the additional installations in the 4.4 GW scenario). Overall, the additional areas have much higher installation density (MW/km2) compared to the 2020 report, as can be seen in Figure 86.

Name	Installed capacity (MW)	Turbine capacity (MW)	Area (km2)	Installation density (MW/km^2)
Kavel 1	700	17	46	15.2
Kavel 2	1400	17	103	13.6
Kavel 3	1400	20	107	13.1

Figure 86 : The additional installation areas

5.3.3. Technology

Based on the analysis of trends from historical wind turbine data carried out in the 2020 report, information of future turbines from the manufacturers, and the Technology Catalogue from the Danish Energy Agency[24], technology scenarios for future offshore wind power plants to be commissioned towards 2030 are created. The 2020 report envisioned 12 MW turbines to be available for 2026-2028 installations.

However, since then the Technology Catalogue from the Danish Energy Agency has updated the expected turbine size by 2030 to be 20 MW, with 15 MW turbines expected for 2025 installations and considering that the analyzed installation years are also 2 years further in the future (2029-2030, compared to 2026-2028 in the 2020 report), the expected turbine sizes for the additional zones are thus increased to 17 MW for installation before 2030, and 20 MW for installations in 2030. The selected turbine sizes align with feedback received from the stakeholders. It is expected that there will be a few MW range of rated power from different manufacturers, but this is not expected to have significant impact on the results. Note that due to the update of the planning it can be assumed that a larger share of newly installed wind power will be based on the larger turbines (e.g. 1400 MW instead of 700 MW modelled in the study).

This study does not aim to use specific manufacturer technologies for the future wind turbines, but rather makes generic assumptions and supplement with sensitivity analyses where manufacturer differences and other uncertainties are considered important for the expected results regarding ramping and behavior

[24] *Danish Energy Agency, Technology Catalogue. Downloaded in March 2022 from: https://ens.dk/en/our-services/projections-and-models/technology-data/technology-data-generation-electricity-and*

during storms. To consider the variation in specific power (W/m2), similar as in 2020 report, two technology scenarios, Tech A and Tech B, as listed in Figure 87. It shows the assumptions for installations taking place before 2030 and in 2030.

The two technology scenarios assume same rated power but different specific power (W/m2). From the available information about offshore wind turbines, we have observed significant differences in specific power which will impact power curves and thereby have possible impacts on ramp rates for wind speeds below the rated power. The technology scenarios Tech A and Tech B are designed to cover the expected range of specific powers in offshore wind installations towards 2030[25]. The range of specific powers is in line with the Technology Catalogue from the Danish Energy Agency, although in this study an even wider range is considered. The specific powers of the largest recently unveiled offshore wind turbines are within the range of Tech A and Tech B, as are the turbines analyzed in a recent study conducted by 3E [26].

The resulting rotor diameters in the tables are a result of the rated power and specific power choices, and they align with feedback from the stakeholders. The hub heights are increased compared to the 2020 report, as the turbines are expected to be physically larger.

	Before 2030		As from 2030	
Technology scenario	A	B	A	B
Rated power	17 MW	17 MW	20 MW	20 MW
Rotor diameter	219 m	262 m	238 m	284 m
Hub height	140 m	165 m	150 m	175 m
Specific power	450 W/m2	316 W/m2	450 W/m2	316 W/m2

Figure 87 : Technology scenarios for offshore wind turbines for additional installations before 2030

The above assumptions lead to the power curves shown in Figure 87 for the two technology scenarios, Tech A and Tech B. Similar to the first study, new generation turbines are expected to fit with Tech A or

[25] Note that considering the planning at the start of the simulations, 700 + 1400 MW was assumed to be installed before 2030, compared to only 700 MW in the latest scenario.

[26] More info: https://economie.fgov.be/sites/default/files/Files/Energy/LCOE-offshore-wind-in-the-Princess-zone.pdf

Tech B (next generation) assumptions. It is noted that newest turbines in the existing fleet confirm a good fit with the Tech A scenario.

On top of this, based on manufacturer brochures and literature review, three high wind speed technology scenarios are studied also shown in Figure 88. The storm shutdown types, and shutdown and restart limits are the same as in the 2020 report, as no new information was received to suggest that they should be changed.

- For 25 Direct cut-off, which is considered as baseline, the wind turbine will shut down when the 10-minute average wind speed exceeds 25 m/s;
- For HWS Moderate, the power will reduce for increasing wind speeds until the wind turbine shuts down at 28 m/s;
- Finally, for HWS Deep, the power will reduce for increasing wind speeds until the wind turbine shuts down at 31 m/s.

It was observed that the HWS Deep type is similar to the storm shutdown technologies already installed in recently commissioned wind power plants in Belgium. Note that Elia recommended the HWS Deep as technical requirement. No information is currently available on new storm control capabilities.

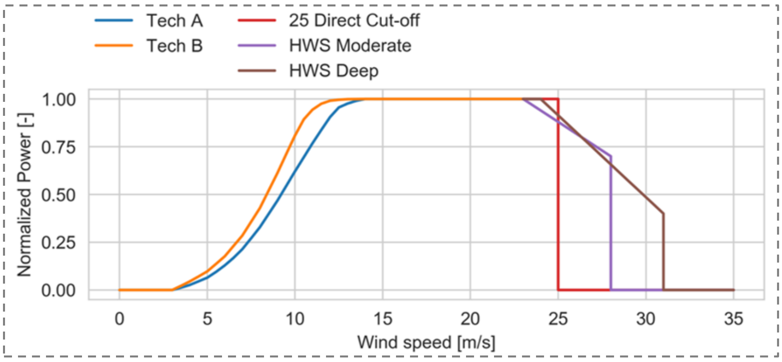


Figure 88 : Power curves for assumed technology scenarios and storm shutdown type

5.4. Offshore generation profiles

5.4.1. Methodology

The methodology used by DTU to model wind power generation and prediction profiles, and the references to the tools used are elaborately dealt with in Section 4 of the DTU Technical Report (Annex 1). An overview of the approach is given in Figure 89. The scenarios towards 2030 are already specified in Section 2.1 and are used by DTU to model the wind power generation and prediction for the foreseen 5.8 GW offshore generation fleet in Belgium, including the foreseen 3.5 GW new capacity to be constructed between 2029 and 2030. The model itself is validated by means of historic observations on the currently installed 2.3 GW.

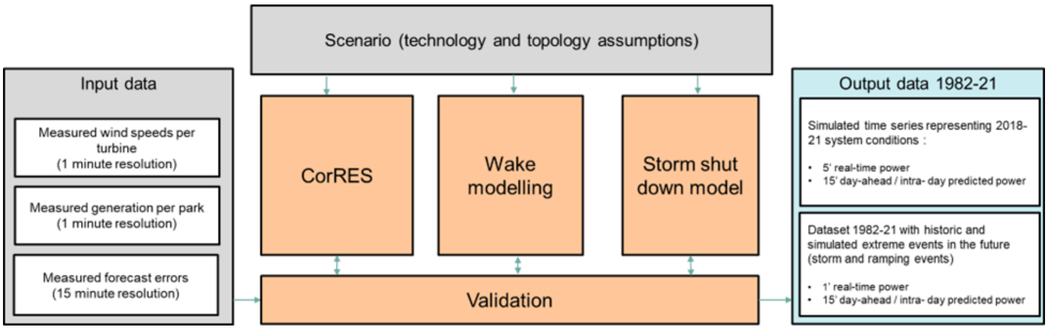


Figure 89 : Overview of the methodology to simulate future offshore wind power generation and prediction profiles

5.4.1.1 CorRES

CorRES[27] is DTU's Wind Energy tool for the simulation of wind power time series with realistic spatial and temporal correlations. It uses a database of weather time series in hourly resolution as input. All simulations are carried out using meteorological data from 1982 until 2021 included. The meteorological data are updated compared to the previous MOG 2 system integration study report to the newest ERA5 re-analysis data from the European Centre for Medium-Range Weather Forecasts. The meteorological data are updated compared to the previous study by including 2020 and 2021.

CorRES includes intra-hour fluctuations and includes turbulent fluctuations within a 10-minute resolution. These fluctuations are added to the hourly weather data using stochastic simulations. CorRES simulations are typically carried out with a resolution of 5 minutes. For extreme ramp and storm cases, interpolated 1-minute resolution data are provided around each extreme case. For calibrating the plant level storm shut down model, specific storm cases were even simulated on a 1-second resolution. The combination of large-scale weather data and stochastic simulation allows for two types of simulations:

- Large scale regions on continental domains with several wind power plants in resolutions of up to 5 minutes over 40 years. A resolution of 5 minutes has been selected as it provides the best trade-off between the computational time to generate time series representing several years and the limited added information of using higher resolutions. For each simulation, a reduced 15-min resolution dataset is created by taking the mean of each variable in 5-minute resolution (or 1-minute resolution for the measured datasets) within each 15-min period;

[27] *More info: https://corres.windenergy.dtu.dk/*

- Detailed plant simulations that model each individual turbine in resolution of up to 1 second. The latter are used to study the impact of storm protection technologies, which are usually specified on turbine-level rather than plant-level.

Impact of Climate Change on wind speed behavior

The literature on the impact of climate change on wind speeds primarily focuses on average wind speeds and continental-level changes in Europe rather than country-level analysis. Based on academic literature, several key aspects have been identified in the IPCC Report on Climate Change (2022):

- *firstly, there is medium evidence and moderate agreement that wind resources are likely to increase in Northern Europe and decrease in Southern Europe due to climate change;*
- *secondly, there is limited evidence suggesting that extreme wind speeds, which can potentially damage wind turbines, may increase as a result of climate change;*
- *additionally, future wind generation in Europe could decrease during summer and autumn while increasing in winter in northern-central Europe but decreasing in the southern-most regions.*

However, when examining storms in Europe more broadly, a report from the Joint Research Centre (JRC) indicates that climate model projections suggest minimal changes in wind hazard with global warming in Europe (JRC, 2020). This finding aligns with the aforementioned literature.

DTU concluded that the uncertainty associated with changes in wind speeds in Europe due to climate change appears to be substantial. Although the average changes mentioned earlier may hold, the model-to-model uncertainty outweighs the impact of climate change when looking at the average results. In other words, the noise in the models seems to remain too large to derive solid conclusions. For these reasons, no evolutions related to climate change are taken into account in the simulations.

IPCC(2022): https://www.ipcc.ch/report/sixth-assessment-report-working-group-3/
JRC(2020): https://joint-research-centre.ec.europa.eu/system/files/2020-05/pesetaiv_task_13_windstorms_final_report.pdf

5.4.1.2 Wake Modelling

As turbines and plants in the Belgium offshore fleet are often tightly spaced, significant wake effects are expected. A wake is the reduction of available energy in the wind after it passes a turbine. DTU's PyWake software[28] was used to simulate wake losses by generating a plant power curve, simulating the power output of the plant as a function of the mean wind speed and mean wind direction over the whole plant. The plant power curve includes the wakes produced by other plants nearby, by modelling all the turbines within 40 km distance from each turbine within the plant. Finally, CorRES uses the plant power curves to simulate the power produced by each plant on each time stamp. The assumptions on the power plant power curves used are presented in Section 5.3.3.

While the modelling considers the farm-to-farm wake losses, the so-called mesoscale losses are not considered. This refers to the lack of energy recovery in the atmosphere. The mesoscale losses impact very large installations, and this effect could become significant in the 5.8 GW scenario. This means that the reported capacity factors may be slightly overestimated but no substantial impact is expected on the forecast errors or variability of generation during storm or ramping events studied in this report.

5.4.1.3 Storm shutdown behavior

When simulating multiple years of generation time series with CorRES on a 5-minute resolution for multiple wind farms, the simulations need to be done on wind park level as the simulation of individual turbines is not feasible for such long time series. However, as the storm shutdown behaviors is specified on turbine level, the behavior of the different shut down technologies need to be modelled on turbine level:

- Individual turbine shutdown can be modelled in simulations with up to a 1-second resolution in CorRES (while the weather data are hourly, CorRES creates up to 1-second time series using stochastic simulation). These simulations are used to study how a specific turbine high wind speed technology translates into the plant level shutdown and re-start behavior. In these simulations, each turbine in a plant is modelled. Because of the high temporal resolution and turbine-level resolution of these simulations, only specific events (one or a few days) are simulated. A selection of high wind speed events has been taken from the 40 years of weather data to represent multiple high wind cases.
- In addition to the shutdown operation, the turbine level model considers the re-start operation. After the shutdown, the wind speed must get lower than the restart limit before the turbine starts to produce again. This effect is called hysteresis: it causes a time lag between the shutdown and restart operation, as it takes some time before wind speed gets lower than the restart limit after a storm event.

[28] *More info: https://topfarm.pages.windenergy.dtu.dk/PyWake/*

5.4.1.4 Scaling of measured forecast errors for the period 2018-2021

The forecast simulation part in CorRES is based on a stochastic model, which simulates wind forecast error distributions and the spatial and temporal dependencies in the forecast errors between offshore wind power farms. However, the simulated high and low forecast errors do not necessarily occur at the same timestamps as in measured data (note that this is different compared to the modelling of actual wind generation in CorRES, which is based on weather data which ensures that the low and high actual generation occur at approximately the same timestamps in measured and simulated data).

In order to use the simulated offshore wind forecast errors with measured data, e.g., for aggregation with forecast errors on onshore wind and solar power, a scaling procedure was created. The procedure allows the simulated actual offshore wind generation data from CorRES to be used with scaled measured Elia forecast data. In other words, the high and low forecast errors will then occur approximately at the same time as in the measured data. The procedure is based on observed forecast errors. As a final step, scaled forecast errors were calculated for all scenarios of interest to represent the forecasts and forecast errors statistics for the period 2018-2021 for offshore wind installed capacity up to 5.8 GW in the Belgian waters.

5.4.2. Validation

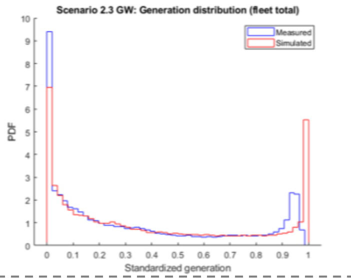
This section presents the main results of the validation process of the simulation model constructed by DTU. Detailed results can be found in Section 5 of the DTU technical report (for the 877 MW case until 2019, and the full 2.3 GW as from 2020 which will be the focus of this summary). This validation step holds significant importance as it helps establish trust and credibility in the model. By comparing the simulated wind speed and generation time series with the actual measurements, it is possible to assess the accuracy and reliability of the model's predictions. Building upon this validation, the same model will then be applied to simulate scenarios involving up to 5.8 GW of offshore wind capacity in Belgium.

The 877 MW case (representing the commissioning of the first farms until 2019) is mainly applied to allow comparison of the results with the previous study and is validated for a period from mid-2017 until 2019. The capacity factors and ramp events give a good fit, similar as in the MOG 2 system integration study (2020), while the high wind speed events, forecast errors and correlation between the simulated and the measured ramps even show a slightly better accuracy. This is explained by the updated meteorological data.

For the 2.3 GW case, validation is applied for a period from December 2020 to the end of 2021. As it was found that observed one minute generation ramps exceeded weather related variations, the data was filtered by removing periods where positive imbalance prices are negative. The validation process concluded that:

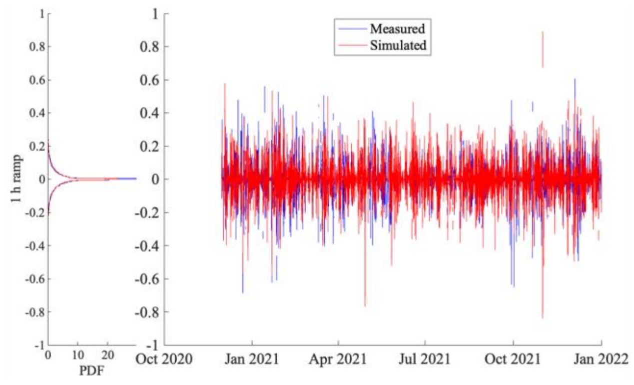
- capacity factors and generation distribution reveals that the simulated capacity factor (CF) tends to be slightly higher than the measured values, even when taking into account a typical unavailability rate of 5% (CorRES runs assume 100% availability). This disparity can be attributed to the possibility that recently commissioned plants may not have operated at full capacity continuously;
- analysis of the generation shows that 5-, 15- and 60-minute (Figure 90) ramps are well captured by the model, as well as the high wind speed events, forecast errors, the relation between the wind speeds and the generation (including during high wind speed events) and the correlation between the measured and simulated ramps and the forecast errors.

The model validation shows that CorRES can model the generation time series of the existing offshore wind power plants in Belgium (as well the initial 877 MW case of the MOG 2 study, as the full 2.3 GW case commissioning in 2020) with a good accuracy. It is thus considered valid for modelling the Belgian offshore capacity extension from 2.3 GW to 5.8 GW. The use of 40 years of meteorological data in simulations for higher installed capacities ensures that a wide range of extreme events are simulated.



	Capacity factor	Standard deviation
Measured	0.339	0.335
Simulated	0.386	0.353
Simulated (5% unavailability)	0.367	

Figure 90 : Generation distribution of the 2.3 GW validation case



	mean	SD	min	Prct 0.1	Prct 1	Prct 5	Prct 95	Prct 99	Prct 99.9	max
Measured	-0.001	0.069	-0.686	-0.388	-0.208	-0.109	0.108	0.205	0.362	0.607
Simulated	0.000	0.077	-0.839	-0.415	-0.214	-0.125	0.124	0.225	0.367	0.892

Figure 91 : Distribution, time series and statistics of one hour generation ramps (expressed per unit)

5.4.3. Results

5.4.3.1 General results on generation

Capacity factors (CF) and standard deviations (SD) of the aggregate generation of the entire offshore wind power fleet in the different scenarios are given in Figure 92. Full results are presented in Section 6 of DTU's report, including statistics for the additional installations are shown (coming on top of the existing 2.3 GW). It is reminded that unavailability of wind turbines and other losses than wake losses are not taken into account in the simulations.

			CF	SD	CF compared to 0.9 GW	SD compared to 0.9 GW
0.9 GW			0.420	0.355	100%	100%
2.3 GW			0.425	0.365	101%	103%
3.0 GW	**Tech A**	**25 m/s**	0.433	0.364	103%	103%
		Moderate	0.433	0.365	103%	103%
		Deep	0.433	0.365	103%	103%
	Tech B	**25 m/s**	0.447	0.365	106%	103%
		Moderate	0.447	0.366	106%	103%
		Deep	0.448	0.366	107%	103%
4.4 GW	**Tech A**	**25 m/s**	0.436	0.363	104%	102%
		Moderate	0.437	0.363	104%	102%
		Deep	0.437	0.364	104%	102%
	Tech B	**25 m/s**	0.466	0.367	111%	103%
		Moderate	0.467	0.368	111%	104%
		Deep	0.468	0.368	111%	104%
5.8 GW	**Tech A**	**25 m/s**	0.436	0.362	104%	102%
		Moderate	0.437	0.363	104%	102%
		Deep	0.438	0.363	104%	102%
	Tech B	**25 m/s**	0.472	0.369	112%	104%
		Moderate	0.474	0.370	113%	104%
		Deep	0.475	0.370	113%	104%

Figure 92 : Capacity factors and standard deviations for entire 5.8 GW fleet (from the 40 years of simulations on 5 min resolution. Only wake losses are considered (availability of 100% is assumed))

The capacity factor of the aggregated fleet is expected to increase from today towards the 5.8 GW scenarios, with Tech B showing significant increase compared to Tech A. The higher capacity factors are driven by higher hub heights (subject to higher wind speeds) and lower specific power turbines (resulting in higher generation at lower wind speeds), particularly for the Tech B. Higher capacity factors imply higher annual offshore generation with the same installed capacity. Storm events remain relatively rare and there are therefore only very small differences observed between the different storm shut down technology types despite the ability of moderate and deep technology types to continue generating at higher wind speeds and come back earlier after a cut off.

Note that the resulting wake losses of 11.2% - 12.0% in this study for the additional installations in the 5.8 GW scenario (e.g., 3.5 GW of additional installations) are similar to other studies published [29], where the most similar technology, e.g., 17MW_Generic, shows a wake loss of 11.9% for a similar scenario.

Figure 92 shows that the standard deviation increases only slightly towards the 5.8 GW scenarios, with Tech B showing marginally higher standard deviation than Tech A. Overall, the simulated standard deviation is slightly higher than in the MOG 2 2020 report which is due to higher hub heights assumed (both in Tech A and Tech B), as well as other model and weather data updates.

5.4.3.2 Ramping events

This chapter presents the results on ramping events for the studied scenarios. As with all the scenario results, these are based on the 40 years of simulations from 1982 to 2021, simulated with a 5-minute resolution. Each individual wind park is simulated, although only aggregated ramp results are reported. Full results are presented in Section 7 of the DTU report.

This section focuses on the analyses of the ramping events in terms of standardized (% of installed capacity) and absolute (MW) generation as presented in Section 7.1 and 7.2 of DTU's report. It is however to be noted that the storm events are not filtered out of the data in these analyses, which means that the ramps that occur during the cut-out and the cut-in phases of storms is included in the statistics presented. To isolate the ramp events which are not related to storms events, Section 7.3 of DTU's report depicts the results for those days when the maximum daily wind speed is below 20 m/s.

Furthermore, this section focuses on the 1-hour ramping events, as those are expected to have the most significant impact on real-time system operation but DTU's report also includes the results for 5- and 15-minutes ramping events. It is to be noted that time series are delivered to Elia in to evaluate the impact on real-time system operations for specific events up to a 1-minute resolution and allow to make a clear distinction between ramping and storm events.

[29] *Report "LCOE offshore wind in the Princess Elisabeth zone", 3E, Sep 2021.*

► Standardized generation variations

Figure 93 shows the standard deviation (SD) and the highest percentiles (Prct) of up- and downward hourly ramps (calculated as the difference in generation between T and T+60 minutes, and expressed as standardized generation, i.e. being relatively to the installed capacity) events of the hourly ramps show a slight decrease of the largest ramps when comparing the BE 2018 (0.9 GW) scenario with the full BE 2030 (5.8 GW) scenario in 2030, at least for the scenarios with moderate and deep storm shut down technologies. Note that this decrease in variability is substantially lower when studying the 5 minute and 15-minute ramps.

The deep and moderate storm shutdown types show slightly decreased likelihoods for the most extreme ramps compared to the 25 m/s cut-off in. The ramp distributions tend to be skewed slightly meaning that there are more extreme upward ramps than downward ramps, especially for the deep technologies. This is driven by the difference in how the wind farms operate at shut down (with a gradual ramp down) versus at the return from a storm (with an instantaneous ramp up). It will be seen later in this report that an up-ward ramp will also be shown to be easier to manage than a downward ramp. As expected, Tech B shows higher ramps than Tech A due to the steeper power curve during normal wind conditions.

								Compared to 0.9 GW		
			SD	**Prct 0.01**	**Prct 0.1**	**Prct 99.9**	**Prct 99.99**	**SD**	**Prct 0.1**	**Prct 99.9**
0.9 GW			0.076	-0.506	-0.350	0.381	0.644	100%	100%	100%
2.3 GW			0.075	-0.493	-0.354	0.380	0.595	100%	101%	100%
3.0 GW	**Tech A**	**25 m/s**	0.073	-0.473	-0.343	0.372	0.564	97%	98%	98%
		Moderate	0.073	-0.481	-0.344	0.372	0.569	97%	98%	98%
		Deep	0.073	-0.472	-0.340	0.368	0.562	97%	97%	97%
	Tech B	**25 m/s**	0.074	-0.479	-0.344	0.367	0.545	98%	98%	96%
		Moderate	0.074	-0.485	-0.346	0.368	0.551	97%	99%	97%
		Deep	0.073	-0.481	-0.343	0.364	0.551	97%	98%	96%
4.4 GW	**Tech A**	**25 m/s**	0.071	-0.513	-0.339	0.365	0.574	95%	97%	96%
		Moderate	0.071	-0.486	-0.328	0.354	0.571	94%	94%	93%
		Deep	0.070	-0.446	-0.322	0.347	0.532	93%	92%	91%
	Tech B	**25 m/s**	0.073	-0.506	-0.351	0.367	0.553	97%	100%	96%
		Moderate	0.072	-0.502	-0.342	0.357	0.577	96%	97%	94%
		Deep	0.072	-0.465	-0.333	0.349	0.524	95%	95%	92%
5.8 GW	**Tech A**	**25 m/s**	0.072	-0.573	-0.345	0.374	0.633	95%	98%	98%
		Moderate	0.071	-0.504	-0.328	0.359	0.603	94%	94%	94%
		Deep	0.070	-0.447	-0.318	0.348	0.536	93%	91%	91%
	Tech B	**25 m/s**	0.074	-0.583	-0.369	0.387	0.625	98%	105%	102%
		Moderate	0.073	-0.522	-0.347	0.368	0.626	96%	99%	97%
		Deep	0.072	-0.471	-0.337	0.358	0.556	96%	96%	94%

Figure 93 : 1 h ramps statistics (standardized generations)

► Absolute generation variations

Figure 94 shows the average number of days per year with at least one ramping event more extreme than the given GW value for 1 hour ramping events. The trends over different scenarios studies are the same as above but the scenarios with more installed GW of course show more extreme ramping events:

- It is shown that for the Tech B and Deep HWS technology downward ramps of 4.0 GW occur less than one time per year and ramps of 2.5 GW are expected to occur multiple times per year for the 5.8 GW scenarios. Note that these downward ramps are reduced to respectively 1.5 GW and 1.0 GW for 15 minutes and respectively 1.0 GW and 0.5 GW for 5 minutes.
- It is shown that in contrast, upward ramps of 5.5 GW can occur less than one time per year and ramps of 3.0 GW are expected to occur multiple times per year. Note that when filtering out storm events (days with maximum wind speeds above 20 m/sec, calculated as the weighted mean over the fleet), this is reduced to respectively 4.0 GW and 2.5 GW being the same values for down-ward ramps. This shows that the asymmetry is mainly caused by storm events.

In conclusion, up- and downward ramping events are expected to increase significantly in the future. It is reminded most extreme ramp events may be underestimated, following the results of the model validation.

			Negative Ramp (GW)												Positive Ramp (GW)											
			5.5	5.0	4.5	4.0	3.5	3.0	2.5	2.0	1.5	1.0	0.5	0.3	0.3	0.5	1.0	1.5	2.0	2.5	3.0	3.5	4.0	4.5	5.0	5.5
0.9 GW													1.0	25	29	2.9										
2.3 GW											0.20	6.4	130	249	248	133	9.4	1.2	0.20							
3.0 GW	Tech A	25 m/s								0.10	1.6	23	193	281	280	193	27	3.7	0.60	0.13	0.05					
		Moderate								0.13	1.9	23	191	280	278	191	26	3.8	0.70	0.15	0.05					
		Deep								0.08	1.5	22	191	279	278	191	26	3.6	0.60	0.15	0.03					
	Tech B	25 m/s								0.10	1.7	24	196	283	283	196	26	3.5	0.53	0.13	0.05					
		Moderate								0.15	1.9	24	194	281	281	194	25	3.6	0.63	0.13	0.03					
		Deep								0.10	1.7	23	193	281	280	193	25	3.4	0.63	0.15	0.05					
4.4 GW	Tech A	25 m/s					0.03	0.23	0.90	3.8	16	84	257	313	311	256	91	20	6.0	2.0	0.55	0.28	0.13			
		Moderate					0.03	0.13	0.63	2.9	14	82	255	312	310	254	89	18	4.8	1.8	0.70	0.33	0.15			
		Deep					0.03	0.05	0.23	1.9	13	81	255	312	310	254	88	17	4.0	1.3	0.48	0.25	0.13			
	Tech B	25 m/s					0.03	0.13	0.80	5.0	20	96	261	315	313	260	98	22	5.8	1.7	0.38	0.23	0.13			
		Moderate					0.03	0.13	0.90	3.8	18	93	259	313	311	257	96	20	4.8	1.8	0.63	0.30	0.13			
		Deep					0.03	0.08	0.43	2.7	17	92	258	313	311	257	94	19	3.9	1.2	0.48	0.28	0.13			
5.8 GW	Tech A	25 m/s	0.03	0.03	0.08	0.58	1.4	2.8	6.0	15	52	160	291	328	327	291	165	58	19	8.4	4.2	2.4	0.90	0.33	0.15	0.08
		Moderate		0.03	0.05	0.23	0.65	1.6	4.2	13	49	158	289	327	326	289	162	56	17	6.6	3.1	1.6	1.0	0.45	0.23	0.13
		Deep				0.05	0.15	0.48	2.9	11	48	157	289	327	326	289	161	54	16	5.5	2.2	0.90	0.45	0.28	0.18	0.05
	Tech B	25 m/s	0.03	0.03	0.05	0.25	1.7	3.7	8.1	20	63	175	293	328	328	292	178	67	24	9.3	4.7	2.6	0.70	0.23	0.13	0.05
		Moderate		0.03	0.05	0.23	0.85	1.9	5.7	17	59	172	291	327	326	290	175	64	21	7.1	3.3	1.9	1.0	0.33	0.18	0.10
		Deep				0.05	0.28	1.0	4.2	15	58	171	291	326	326	290	174	63	19	5.7	2.2	1.1	0.65	0.35	0.20	0.13

Figure 94 : 1-hour ramps - average number of days per year with at least one event more extreme than the limit

5.4.3.3 Storm events

This chapter presents statistics of storm events in the simulated 40 years of data. Both the likelihoods of offshore wind power fleet shutdowns and the ramping during high wind speed days (maximum wind speed above 20 m/s for the weighted average over all the offshore wind parks in terms of installed capacity).

► **Generation during storm**

Simulated offshore wind power wind speeds on fleet level for the 5.8 GW Tech B scenario can be seen in Figure 95 based on a 5-minute resolution. The highest fleet-level wind speed reaches approximately 38 m/s while highest plant-level wind speeds are even higher. It can be observed that high wind speeds occur throughout the 40 years and most extreme peaks occurred in the 1980s and 1990s. It has to be noted that the Tech B scenario shows slightly higher fleet-level wind speeds than Tech A due to higher hub heights.

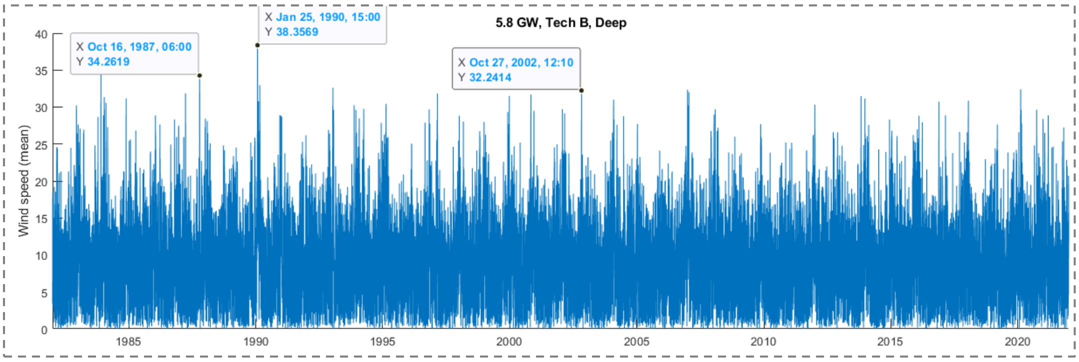


Figure 95 : Fleet-level mean wind speeds (weighted by OWF installed capacity) in the 5.8 GW Tech B scenario (5 min resolution), with some example high peaks highlighted

Example time series around the 1990 extreme high wind speed event can be seen in Figure 95. With such high wind speeds, the entire fleet (5.8 GW) is in shutdown for some hours with all the scenarios considered. In this specific example, the Deep HWS technology type shows lower ramping (both 5 minute and 1 hour) than the 25 m/s cut-off. Note that a full cut-out event was recently observed with the storm Eunice in February 2022.

It is interesting to note that the moderate HWS technology type shows higher 5-minute ramping than the 25 m/s cut-off technologies, even though the cut off happens at higher wind speeds. This is explained as in this example, the wind speed variation is slightly faster around the moderate technology type cut-off wind speeds, causing higher ramps than with the 25 m/s cut-off. This shows that the storm shutdown types should be compared based on statistics over a longer time series rather than on individual cases. The figure also shows how the deep technology types may cause larger upward variations.

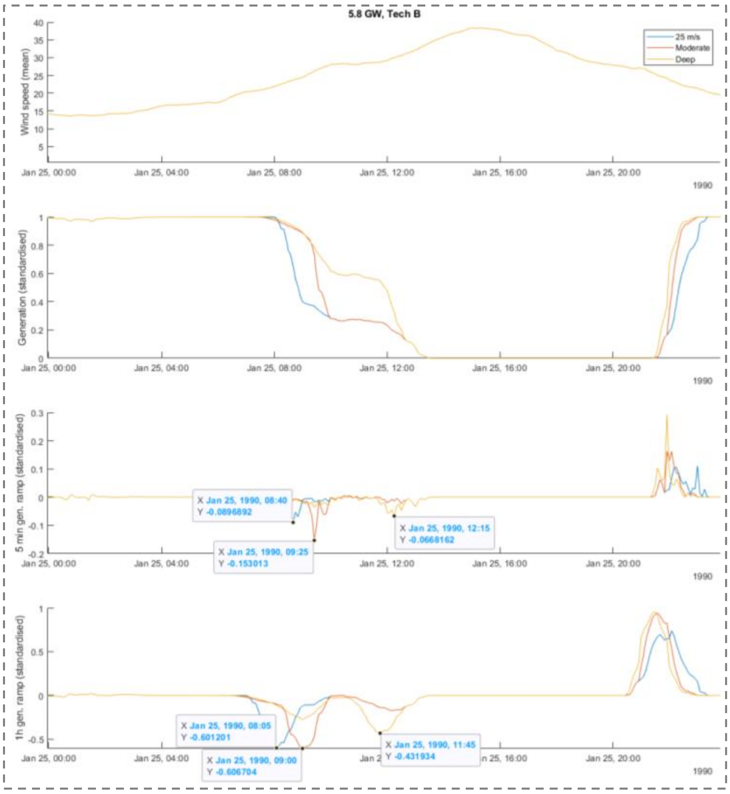


Figure 96 : Simulated time series for an extreme storm case for the 5.8 GW Tech B scenario

Figure 96 shows that even with the deep shutdown technology types, the 5.8 GW Tech B scenario is expected to sometimes experience a total fleet-wide shut-down. The figure shows that this was expected to happen during 6 of the 40 years observed (e.g. every 6 to 7 years). It is further analyzed that the high wind speed technologies have a limited impact in reducing this number of occurrences where the entire fleet experiences a total shut down. Nevertheless, the technology is demonstrated to provide substantial benefits in reducing the total hours in shut down (during events where part of the park is impacted) and the downward ramp during storms.

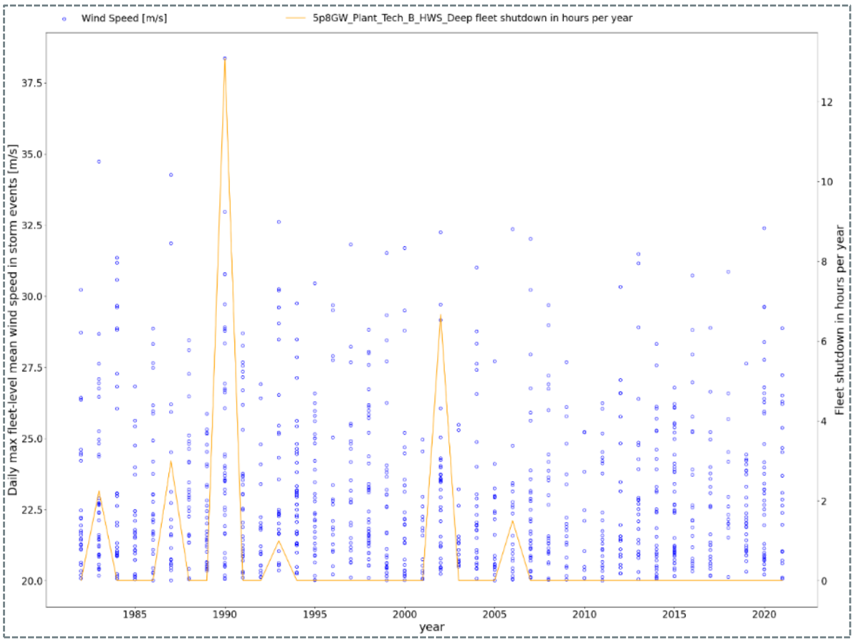


Figure 97 : Number of hours when the entire fleet is in shutdown (aggregate generation zero) per year in the 5.8 GW Tech B Deep scenario (right), and daily max wind speeds above 20 m/s (left) for each year

► Absolute generation variations

Figure 98 shows the average number of days per year with at least one ramping event more extreme than the given GW value for 1 hour ramping events for the high wind speed days. It is shown that the deep shut down technology type reduces likelihoods for large negative ramps. For the 5.8 GW scenario with Tech B:

- the Deep HWS technology type can reduce also the most extreme downward ramps from 5.5 GW (occurring less than one time per year) and 3.0 GW (occurring more than one time per year) to 3.5 GW and 2.0 GW respectively;
- the most extreme positive ramps of 5.5 GW (occurring less than one time per year) remain similar for all types, but the Deep HWS technology types is also found to have an effect on the positive ramps reducing the amount of events happening multiple times per year from 3.5 GW to 2.0 GW.

.

			Negative Ramp (GW)												Positive Ramp (GW)											
			5.5	5.0	4.5	4.0	3.5	3.0	2.5	2.0	1.5	1.0	0.5	0.3	0.3	0.5	1.0	1.5	2.0	2.5	3.0	3.5	4.0	4.5	5.0	5.5
0.9 GW													0.48	3.2	4.4	1.4										
2.3 GW												0.98	7.7	12	12	7.7	1.8	0.53	0.15							
3.0 GW	Tech A	25 m/s								0.05	0.48	3.4	12	15	15	12	4.3	1.3	0.43	0.13	0.05					
		Moderate								0.08	0.70	3.3	11	14	14	11	4.2	1.3	0.53	0.15	0.05					
		Deep								0.03	0.38	2.6	10	14	14	10	3.3	1.2	0.43	0.15	0.03					
	Tech B	25 m/s								0.03	0.55	3.2	13	16	16	13	4.1	1.2	0.38	0.13	0.05					
		Moderate								0.08	0.68	3.5	11	14	14	11	4.0	1.3	0.48	0.13	0.03					
		Deep								0.03	0.53	2.7	10	14	14	10	3.3	1.1	0.48	0.15	0.05					
4.4 GW	Tech A	25 m/s					0.03	0.20	0.83	2.4	4.8	8.9	15	17	17	15	10	5.4	3.2	1.3	0.43	0.23	0.13			
		Moderate					0.03	0.10	0.55	1.5	3.0	6.7	13	15	16	14	8.3	3.9	2.0	1.1	0.58	0.28	0.15			
		Deep					0.03	0.03	0.15	0.48	2.0	5.8	13	15	16	13	7.4	2.6	1.2	0.63	0.35	0.20	0.13			
	Tech B	25 m/s					0.03	0.10	0.58	2.9	5.3	10	15	18	19	16	11	5.7	3.3	1.1	0.28	0.18	0.13			
		Moderate					0.03	0.10	0.68	1.7	3.5	7.3	13	16	17	14	8.4	4.0	2.3	1.3	0.53	0.25	0.13			
		Deep					0.03	0.05	0.20	0.60	2.1	6.2	13	16	17	13	7.1	2.7	1.3	0.60	0.38	0.23	0.13			
5.8 GW	Tech A	25 m/s	0.03	0.03	0.08	0.53	1.4	2.5	3.8	5.6	8.4	12	17	19	19	17	13	9.1	6.2	4.5	3.0	2.1	0.83	0.28	0.15	0.08
		Moderate		0.03	0.05	0.18	0.58	1.3	2.0	3.1	5.7	9.9	15	18	18	16	11	6.6	4.0	2.7	1.9	1.3	0.88	0.40	0.23	0.13
		Deep					0.08	0.20	0.65	1.7	4.6	9.6	15	18	18	16	10	5.4	2.7	1.5	1.0	0.63	0.38	0.23	0.18	0.05
	Tech B	25 m/s	0.03	0.03	0.05	0.20	1.6	3.1	4.7	6.6	9.6	14	18	20	20	18	14	10	7.1	5.2	3.6	2.3	0.60	0.20	0.13	0.05
		Moderate		0.03	0.05	0.18	0.73	1.3	2.3	3.7	6.3	11	16	19	19	16	11	7.2	4.4	2.9	2.2	1.6	0.90	0.30	0.18	0.10
		Deep					0.15	0.33	0.80	2.2	4.8	9.9	16	19	19	16	10	5.6	2.9	1.5	1.1	0.78	0.55	0.33	0.20	0.13

Figure 98 : 1 h ramps: average number of days per year with at least one event more extreme than the limit, for days with max fleet-level wind speed above 20 m/s

5.4.3.4 Forecast errors

This chapter summarizes the analyses of the simulated forecast errors for the scenarios. Full results are presented in Section 9 of the DTU report including:

- an analysis of the forecast errors in terms of standardized (% of installed capacity) and absolute (MW) generation for the day-ahead, intraday and last forecast;
- an analysis of the forecast errors during high and low wind speed days, as well as days with high ramps and storms.

This chapter focusses mainly on the day-ahead forecasts. The forecast errors are always calculated as e_t=p_(t,actual)-p_(t,forecasted) which means that a negative forecast error corresponds with an overestimation and thus a shortage wind power generation. All forecast errors are analysed on a 15-minute resolution. It is important to note that it would be irrelevant to use simulated forecast errors for one specific event obtained from the time series, as the objective is not to replicate forecast of a particular event but to represent overall forecast uncertainty. The analysis is performed aiming at 2 objectives:

1. provide a global statistical analysis allowing to gain knowledge in forecast errors to be expected in normal and extreme conditions, and in particular (1) assess if the increased geographical spread of installations impacts the fleet level forecast errors (2) study if storm shut down technology impacts the forecast errors;

2. provide the fleet-level forecast errors for the years 2018 – 2021 for a 2.3 GW, 3.0 GW and 5.8 GW offshore fleet. This is used as input for the analyses of the impact on Elia's reserve needs in Section 4 of this report.

► **Standardized results**

Figure 99 shows the day-ahead forecast error statistics for the different scenarios expressed in standardized generation. It can be seen that the standard deviation (SD), used as a measure for the absolute forecast accuracy (compared to the mean which indicates the symmetry of the forecasts), decreases slightly towards the 5.8 GW scenarios when compared to the BE 2018 scenario (0.9 GW). This decrease is due to increased geographical distribution as in general, it is easier to forecast a larger than a smaller region. Tech A and Tech B scenarios show similar statistics while the Deep HWS technology type shows very slightly reduced likelihoods in the last forecast for very large forecast errors compared to 25 m/sec direct cut-off.

Analysis of the intraday forecast show, as expected, lower standard deviations compared to day-ahead, while the last forecast is showing lower standard deviations compared to the intraday. For example, the standard deviation of 0.114 in the 5.8 GW Tech B Deep scenario is reduced to 0.090 and 0.065 when moving respectively to the intraday and last forecast.

									Compared to 0.9 GW
			Mean	**SD**	**P0.001**	**P0.01**	**P99.99**	**Pr99.999**	**SD**
0.9 GW			-0.003	0.128	-0.818	-0.669	0.704	0.900	100%
2.3 GW			-0.003	0.126	-0.735	-0.650	0.656	0.836	99%
3.0 GW	**Tech A**	**25 m/s**	-0.002	0.121	-0.719	-0.639	0.622	0.714	95%
		Moderate	-0.002	0.121	-0.738	-0.641	0.624	0.729	95%
		Deep	-0.002	0.121	-0.740	-0.640	0.624	0.737	94%
	Tech B	**25 m/s**	-0.002	0.121	-0.719	-0.643	0.618	0.706	95%
		Moderate	-0.002	0.121	-0.719	-0.644	0.620	0.709	95%
		Deep	-0.002	0.121	-0.739	-0.644	0.622	0.728	95%
4.4 GW	**Tech A**	**25 m/s**	-0.002	0.114	-0.673	-0.601	0.648	0.810	89%
		Moderate	-0.003	0.113	-0.676	-0.602	0.646	0.823	89%
		Deep	-0.003	0.113	-0.672	-0.594	0.637	0.823	88%
	Tech B	**25 m/s**	-0.001	0.116	-0.674	-0.602	0.661	0.787	91%
		Moderate	-0.002	0.115	-0.674	-0.604	0.662	0.799	90%
		Deep	-0.002	0.115	-0.674	-0.601	0.660	0.800	90%
5.8 GW	**Tech A**	**25 m/s**	-0.003	0.113	-0.731	-0.608	0.647	0.745	88%
		Moderate	-0.003	0.112	-0.763	-0.639	0.636	0.763	87%
		Deep	-0.003	0.111	-0.725	-0.589	0.584	0.757	87%
	Tech B	**25 m/s**	-0.002	0.116	-0.711	-0.608	0.636	0.701	91%
		Moderate	-0.002	0.115	-0.741	-0.644	0.640	0.747	90%
		Deep	-0.002	0.114	-0.733	-0.605	0.608	0.766	89%

Figure 99 : Day-head forecast error statistics

► Absolute results

Figure 100 shows the average number of days per year with at least one day-ahead forecast error more extreme than the given GW limit. Tech A and Tech B scenarios show similar statistics and the results indicate again that largest forecast errors are slightly less likely for the Deep HWS technologies compared to 25 m/sec direct cut-off. This is due to the fact that for high wind speed days, the Deep type reduce generation forecast uncertainty (even as the quality of wind speed forecasts is the same) following the wind speed having lower impact on the generation forecast error. It is to be noted that in some cases, this might increase the forecast error during the cut in phase after the storm.

Results show that forecast errors of 3 GW can happen multiple times per year, while higher forecast errors, even up to 4.5 GW are exceptional (less than one time per year). Similarly to Figure 100, largest forecast errors are reduced in intraday and last forecast where the size of forecast errors happening multiple times per year is reduced from 3 GW to 2 GW and exceptional forecast event do not exceed 3.5 GW.

			Negative forecast error (GW)												Positive forecast error (GW)											
			5.5	5.0	4.5	4.0	3.5	3.0	2.5	2.0	1.5	1.0	0.5	0.3	0.3	0.5	1.0	1.5	2.0	2.5	3.0	3.5	4.0	4.5	5.0	5.5
0.9 GW													3.4	45.1	40.4	3.4										
2.3 GW											0.8	19.3	110.0	181.5	181.2	108.1	17.8	0.8	0.1							
3.0 GW	Tech A	25 m/s								0.5	6.6	40.4	142.3	209.0	209.4	141.1	39.9	6.1	0.3	0.0						
		Moderate								0.5	6.7	40.4	141.3	207.6	207.9	139.6	39.7	6.0	0.3	0.0						
		Deep							0.0	0.5	6.6	40.1	140.8	207.1	207.4	139.0	39.4	5.9	0.4	0.0						
	Tech B	25 m/s								0.6	6.7	40.5	142.9	209.8	211.7	142.7	39.7	5.9	0.4	0.0						
		Moderate								0.6	6.8	40.6	141.9	207.9	209.1	140.8	39.6	5.9	0.4	0.0						
		Deep							0.0	0.6	6.7	40.4	141.1	207.2	208.8	140.1	39.3	5.9	0.4	0.0						
4.4 GW	Tech A	25 m/s						0.1	1.1	6.8	28.5	83.6	186.5	241.9	242.3	187.3	83.5	28.7	7.6	1.4	0.3	0.1				
		Moderate						0.1	1.1	6.6	27.9	82.4	184.4	240.3	240.7	185.1	81.0	27.3	7.0	1.3	0.3	0.1	0.0			
		Deep						0.1	1.0	6.3	27.4	81.7	184.0	239.9	240.4	184.6	80.2	26.4	6.5	1.1	0.3	0.1				
	Tech B	25 m/s						0.1	1.5	7.7	30.2	86.1	188.6	243.7	245.2	191.7	86.9	31.0	9.0	1.5	0.4	0.1				
		Moderate						0.1	1.6	7.6	29.6	84.7	185.9	241.3	242.5	188.8	84.6	29.6	8.6	1.6	0.4	0.1	0.0			
		Deep						0.1	1.4	7.2	29.0	83.9	185.2	240.6	242.2	188.2	83.0	28.7	7.8	1.3	0.4	0.1	0.0			
5.8 GW	Tech A	25 m/s				0.1	0.7	2.8	9.7	27.4	65.6	127.8	220.2	265.8	262.4	216.3	123.1	60.1	25.3	10.1	3.7	1.2	0.3	0.1		
		Moderate		0.0	0.1	0.2	0.7	2.7	9.1	26.4	63.9	125.5	218.0	264.4	261.1	214.1	120.2	57.5	23.1	8.6	2.9	0.8	0.3	0.1		
		Deep				0.1	0.5	2.4	8.7	25.7	63.1	124.6	217.7	263.9	260.8	213.8	119.3	56.4	22.3	7.9	2.4	0.5	0.2	0.1	0.0	
	Tech B	25 m/s				0.2	0.7	3.7	12.1	32.1	70.8	133.0	220.9	265.8	264.6	220.1	128.5	67.0	30.2	12.7	4.4	1.4	0.2	0.1		
		Moderate			0.0	0.3	0.9	3.5	11.4	30.7	69.2	130.3	218.2	263.6	262.6	217.1	124.8	64.1	27.8	11.0	3.5	1.1	0.3	0.1		
		Deep			0.0	0.2	0.6	3.0	11.0	30.1	68.2	129.1	217.5	263.0	262.2	216.5	123.8	62.6	26.8	10.2	3.0	0.7	0.1	0.1		

Figure 100 : Day-ahead forecast errors: average number of days per year with at least one event

► Results for high wind speed days, high ramp days and storm days

DTU's report also includes a comparison between forecast errors during days with and without high wind speed, resulting in the conclusion that large forecast errors are more likely during high wind speed days (fleet-level max wind speed larger than 20 m/s). In general, it is concluded that the largest forecast errors (above 4.5 GW) occur more frequently during high wind power conditions but that no large differences are discovered for lower errors. The Deep HWS technologies shows slightly lower forecast errors during high wind speeds days compared to 25 m/s direct cut-off.

In addition, an analysis of the forecast errors during days with high ramps (defined as “ramping event larger than 2 GW”) and during storm days (defined as “max wind speed larger than 20m/s and ramping event larger than 2 GW”) was conducted. It is found that the Deep HWS technologies show significantly less events (up to 50% less) with high ramp compared to the 25 m/s cut-off shutdown type.

It is further concluded that high ramp and storm days show higher forecast errors. However, due to the relatively small amount of events, in particular for storms, the estimation of forecast error distributions is subject to large uncertainty. It needs to be noted that forecasts are difficult to simulate then, as the target is not to replicate the variability due to weather, but to try to represent the forecasts by the Elia’s forecast provider and to then estimate forecast behavior in future scenarios. For this reason, the results presented for forecasts and forecast errors for the extended capacity scenarios need to be taken as the average evolutions in the forecast errors resulting from different geographical installation distributions and storm shutdown technologies. The actual simulated forecast and forecast error values for an individual event are stochastic and can be high or low due to randomness.

5.4.4. Conclusions

The validation of DTU's CorRES model to analyze the generation time series of the offshore wind power plants towards 2030 is updated based on latest information available on:

- latest wind speeds and wind power generation in Belgium available until 2021;
- latest installed wind power scenarios up to 5.8 GW and offshore wind power layout.

Based on the results of the model validation, **the model is considered suitable for modelling the future offshore wind power generation profiles and corresponding forecasts** which are used for Elia's system simulations and analysis in this report.

When looking at the standardized generation, ramping events are expected to be slightly reduced compared to the 2.3 GW situation of today in relative terms, i.e. in relation to the installed power. This is caused by the effect of considering larger geographical areas typically reducing the effect of wind power variations and forecast errors. Nevertheless, this effect is much lower as typically witnessed for other technologies due to the relatively small Belgian North Sea territory in which wind power can be considered. Despite this effect, large ramping events are expected to be observed with 5.8 GW offshore wind power:

1. It is shown that for the Tech B & Deep HWS technologies, downward ramps of 4.0 GW occur less than one time per year and ramps of 2.5 GW are expected to occur multiple times per year. Note that these downward ramps are reduced to respectively 1.5 GW and 1.0 GW for 15 minutes and respectively 1.0 GW and 0.5 GW for 5 minutes;
2. It is shown that upward ramps of 5.5 GW for the same scenario can occur less than one time per year and ramps of 3.0 GW are expected to occur multiple times per year. Note that when filtering out storm events (days with maximum wind speeds above 20 m/sec, calculated as the weighted mean over the fleet), this is reduced to similar values as with the downward ramps.

Obviously, the storm shut down technology does not play a role when filtering out storm conditions while Tech B result in larger generation variation due to its steeper power curve during normal wind speed conditions, compared to Tech A.

Similar as in the previous study, it is concluded that it is possible to lose the full installed capacity due to an extreme storm event and this in all studied scenarios. The occurrence with which this is expected is 6 or 7 times out of the simulated 40 years. Moderate and Deep storm HWS technologies are found to allow to mitigate the frequency and the system impact of storms in terms of generation variations compared to direct cut off technologies at 25 m/sec, as observed with some existing wind turbines. Nevertheless, these are not found to be able to entirely mitigate the risk of losing the entire fleet during a storm event.

HWS technologies, aiming at maintaining generation at higher wind speeds can reduce the most extreme downward ramps from 5.5 GW (occurring less than one time per year) and 3.0 GW (occurring more than one time per year) to 3.5 GW and 2.0 GW respectively. In contrast, the most extreme positive ramps of 5.5 GW (occurring less than one time per year) remain similar for all technologies although the Deep technology types is also found to have an effect on the positive ramps reducing the amount of events happening multiple times per year from 3.5 GW to 2.0 GW. This is explained as cut in events after storms will happen less frequently with the HWS technologies.

While the Tech A versus B does not play a role when filtering out the storm events, the Deep HWS technologies provide large benefits to system operation, particularly for managing the downward ramps. However, while there is also an effect on mitigating the upward ramps, there is no effect on the most extreme situations. Note that upward ramps are typically easier to handle than downward ramps via cut-in coordination.

The fleet level standardized forecast errors decrease with increasing capacity installed. Results show that large forecast errors of 3 GW can happen multiple times per year, while higher forecast errors, even up to 4.5 GW are exceptional (less than one time per year). Largest forecast errors are reduced in the intraday and last forecast where the size of forecast errors happening multiple times per year is reduced from 3 GW to 2 GW and exceptional forecast event do not exceed 3.5 GW. These figures can be improved with future forecast quality improvements, and it is **important to keep investing in maintaining and improving forecast accuracy.**
DTU's report includes a comparison between forecast errors during days with and without high wind speeds allowing to conclude that large forecast errors are more likely during high wind speed days (fleet-level max wind speed larger than 20 m/sec). In general, it can be concluded that the largest forecast errors (above 4.5 GW) occur more frequently during high wind power conditions.

It is important to note that the effect of climate change has not been considered as no sound conclusions can be drawn at this point on a potential impact of climate change on the frequency and severity of ramping and storm events.

5.5. Impact on Elia's reserve requirements

5.5.1. Introduction

In the MOG 2 system integration study, projections were presented regarding Elia's future reserve capacity needs. These projections are updated in this report. The aim is on the one hand to clarify the impact of the integration of variable renewable generation such as offshore wind on reserve capacity and balancing capacity procurements. On the other hand, this reserve capacity determines the minimum flexibility availability in the system to deal with storm and ramping events and is therefore an important assumption in the system simulations presented in Section 5.6.

The reserve projections are based on the methodology presented in Section 5.5.2 and the same results are already presented in Elia's Adequacy and Flexibility Study 2023. The projections are based on **scenarios** taking into account (1) the ability of market players to balance new renewable generation in their portfolio. This concerns the ability to balance forecast errors related to renewable generation and forced outages based on intraday re-scheduling and reactive balancing; (2) the evolution of the system imbalances related to the existing generation mix; (3) assumptions related to forecast improvements. Note that (1) and (2) are strongly related to the available flexibility in the system. A better coverage of the total flexibility needs of the system will provide better access to flexibility for market players and facilitate them to balance new and existing variable generation and demand in their portfolio.

These scenarios are used to make **projections of system imbalances** up to 2034 by upscaling historic system imbalances considering expected forecast errors related to the future generation mix, and in particular the increase in variable renewable generation. This is based on projections regarding the installed wind and solar power presented in the CENTRAL scenario of Elia's Adequacy and Flexibility Study 2023 study applied on historic time series of forecast errors.

As part of a last step, **estimations regarding future FRR/aFRR/mFRR** needs are calculated based on Elia's dynamic dimensioning methodologies, based on the current legal and regulatory framework. Note that Elia's reserve dimensioning methods are specified in the LFC block operational agreement and are approved by the regulator after public consultation. These results are then further processed towards the balancing capacity to be procured by making assumptions about the expected availability of non-contracted balancing means in the system.

Note that a first analysis was conducted Q4 2022, presented in the Task Force PEZ of January 10, 2023 and the WG BAL workshop of February 15, 2023. An update of a part of the results have been conducted in Q1 2023 to take into account the effect of latest projections on renewable capacity including the updated offshore wind power planning communicated by the Government in Q1 2023. The result of this updated has been presented in Elia's Adequacy and Flexibility Study 2023 as well as this report.

5.5.2. Methodology

In a first step, scenarios are built representing the ability of market players (or the balancing responsible parties) to balance their portfolio. This is based on an analysis of historic LFC block imbalances, BRP portfolio imbalances and offshore generation day-ahead and intraday forecast errors. The scenarios take into account best and worst case estimations on future market performance in dealing with LFC block imbalances.

In a second step, historic LFC block imbalances are scaled up towards 2024-2034. The parameters presented in the next section are used in an iterative formula represented in *Figure 101*. The expected system imbalance for every year 'T' between 2024 and 2034 (SI_T) is calculated for each quarter-hour 't' as follows:

- ***The expected evolution of system imbalances*** *following the balancing performance of BRP portfolios compared to the previous target year (SI_{T-1}). Note that the calculation starts from observed system imbalances for 2020 and 2021 (SI_0). A 1% improvement / deterioration in system imbalances translates into a factor X_T of 99% / 101%*

- ***The contribution of forecast errors related to incremental renewable capacity installed*** *in the system imbalance. This concerns new renewable generation for technology i (PV, Onshore, Offshore) installed between year T-1 and T ($IC_{T;T-1,i}$). The forecast errors are calculated as the difference between the observed real-time generation and day-ahead forecast, expressed as a percentage of the installed capacity. Note that the calculation starts from observed forecast errors for 2020 and 2021 ($FE_{0,i}$). The calculation takes into account:*

    - *An improvement factor representing the improvement of the day-ahead forecast error of a renewable technology. A 1% improvement / deterioration in the forecast quality translates in-to a factor $Y_{T,i}$ of 99% / 101%*

    - *A factor $Z_{T,i}$ representing the share of the forecast errors on the incremental capacity installed of a renewable technology which will not be covered by the market players and therefore contribute to the system imbalance.*

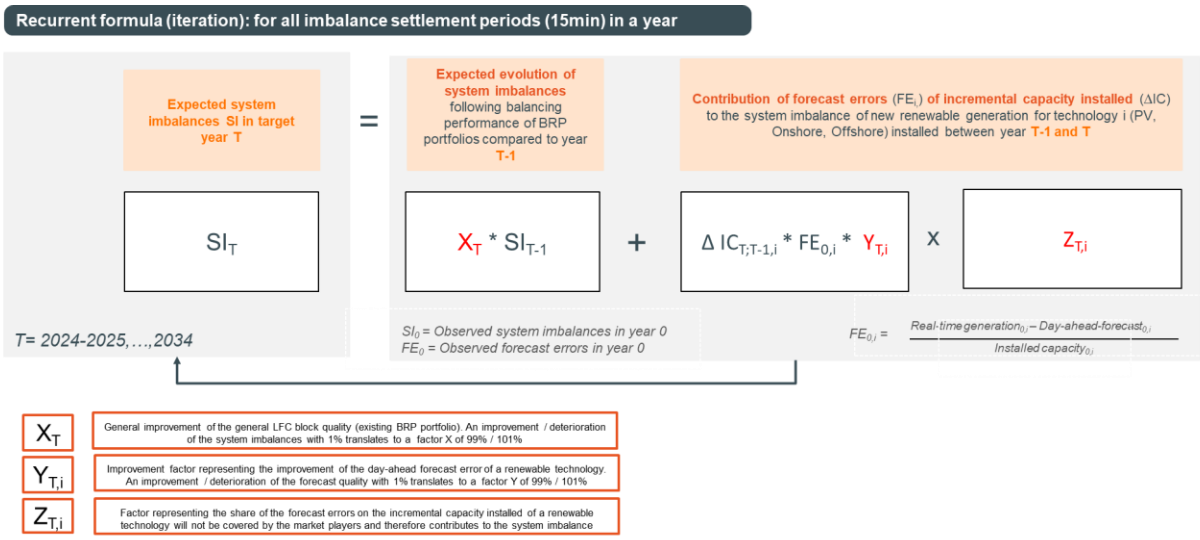


Figure 101 : Visual representation of the methodology used to undertake system imbalance projections

In **the third step**, the current methodology is used to simulate based on these projections the dynamic FRR needs. The upscaled LFC block imbalances are set against the database of predicted system features used in the existing dimensioning methodology to simulate the result of the probabilistic approach. A part of the dataset is used to train the algorithms; the other part is to make simulations for 2024-2034. This allows to determine the average FRR needs, as well as the variability of these FRR needs, taking into account the maximum of the probabilistic results (PROB99), deterministic methods based on the dimensioning incident (DET N-1) and the minimum legal threshold (HIST99). Finally, an estimation is made of the current aFRR needs based on the new methodology to be implemented in 2024 to determine the ratio between aFRR needs and mFRR needs.

5.5.3. Assumptions

5.5.3.1 Belgian technology mix

A. Installed renewable capacity

Figure 102 shows the projections on installed renewable capacity between 2024 and 2034 used to extrapolate system imbalances. These are aligned with the CENTRAL scenario in Adequacy and Flexibility Study 2023. It is noted that the renewable ambitions are much larger compared with the previous study (represented by the dotted lines in the figure) with additional offshore generation as from 2030 (+1.4 GW), the increase speed of photovoltaic power developments (+ 1.6 GW in 2023 and even + 4.0 GW in 2032) and additional onshore wind as from 2026 (+ 0.9 GW in 2032).

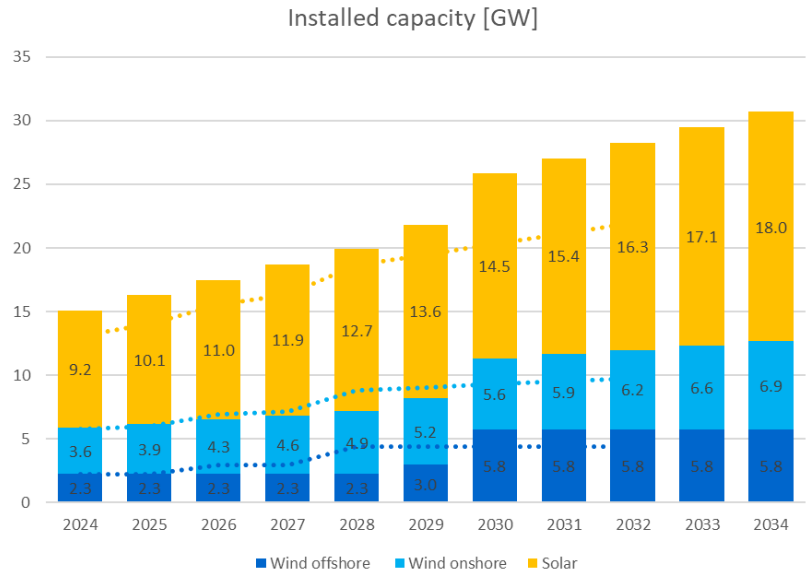


Figure 102 : Installed capacity of offshore wind, onshore wind and solar in Belgium towards 2034 based on CENTRAL scenario Adeqflex'23 (compared to Adeqflex'21 by means of dotted lines)

B. Forced outages of large generation and storage units

Note that also the large generation and storage units affect future imbalances through the forced outages. Also, these capacities have been taken from the CENTRAL scenario in Adequacy and Flexibility Study 2023, including the prolongation of Tihange 3 and Doel 4, as well as two new large CCGT units as from 2025. The forced outage probabilities were also updated in the framework of the study and used for this report as well.

Forced outages of the existing (Nemo Link) and new (Nautilus as from 2030) HVDC interconnectors with UK, as well as with Denmark (Triton Link as from 2032) affect the system imbalances in the Belgian LFC block and are therefore also taken into account based on the forced outage probabilities. To correctly model the impact on the upward and downward reserve needs, the import / export ratio of the interconnectors is taken from observations and available economic dispatch simulations.

Note that the topology of these interconnectors may also affect the calculation of the dimensioning incident, set as a minimum value for the reserve capacity needs as well in upward as downward direction. The current design options for Nautilus / Triton ensure that probability of losing more than 1000 MW remains well under the probability levels currently accounted as dimensioning incident as:

- HVDC system will consist in a full bipole system (e.g. a dedicated metallic return will be foreseen in the cable system). Doing so, a pole failure or a cable failure will only lead to the loss of half of the HVDC system which will not be more than 1000 MW.

- The probability of losing more than 1000 MW only becomes unacceptable when coupling both HVDC systems (PEZ / Nautilus & Triton link) on the island. By design the coupling will only be implemented in presence of a mean to automatically open the coupling after a fault (e.g. HVDC circtuit-breaker) and the probability of losing more than 1000 MW remains sufficiently low.

Furthermore, under normal conditions, no other grid elements related to the Princess Elisabeth Zone (connection of the wind farms to the island, AC connection of the island to the Belgian shore grid, on-shore grid infrastructure) are expected to impact the dimensioning incident. It is therefore concluded that by design, the offshore wind power developments do not substantially impact the dimensioning incident in Elia's LFC block.

As foreseen in the Federal Development Plan, Nautilus (as from 2030) and Triton (as from 2032) will be included in the forced outage simulations in the probabilistic method of the dimensioning (at potential impact of 50% of their installed capacity following the full bi-pole technology).

5.5.3.2 System imbalance and renewable forecast data

To determine future forecast errors to extrapolate the currently observed system imbalances, the day-ahead offshore generation and prediction are taken from DTU's simulations for the 2.3 GW (until 2028 included), 3.0 GW (2029) and 5.8 GW (as from 2030) specified in Section 5.4 of this report and represent future generation and prediction profiles corresponding to weather conditions in 2020 and 2021. This allows to take into account estimated technology and topology of the future offshore wind power fleet on the 15' offshore forecast errors used for FRR / mFRR dimensioning. Furthermore, these time series also represent higher resolutions (up to 5 minutes) which is used to study the effect on aFRR dimensioning. For these reasons, this data is preferred over Elia's measurement and forecast data.

For the onshore wind power and solar forecast errors, the historic results of the day-ahead forecast tools of Elia are used for the same period 2020-21 with a resolution of 15 minutes. The 5 minute resolution is constructed by means of linear interpolation. Also the historic system imbalance data used as basis for the extrapolations is taken from 2020-21.

5.5.3.3 Market performance indicators

The market performance indicators are used to determine the share of future forecast errors if wind, solar and demand will be managed by the market, and which share will effectively contribute to the system imbalance to be managed by Elia with its reserve capacity. Four scenarios were constructed and presented by Elia to stakeholders:

1. *A worst case or 'LOW FLEX' scenario which does not involve the participation of flexible appliances such as home batteries, heat pumps and electric vehicles in the electricity market. In this scenario, there is no enhanced market design and no work is undertaken to address other barriers standing in the way of new flexibility participating in the market. Market players are therefore considered not to be able to balance their portfolios in a suitable manner and the system largely relies on Elia's balancing capacity procurement and activations.*

2. *A best case or 'HIGH FLEX' scenario, which includes the near-full participation of flexible appliances in electricity markets. In this scenario, a facilitating market design is fully and quickly adopted, and work is undertaken to address other identified barriers standing in the way of new flexibility participating in the system. Market players are able to balance their portfolios in a suitable manner and the system will only rely on Elia's balancing capacity procurement and activations as a last resort.*

3. *A 'CENTRAL' scenario, representing Elia's best estimate, which is positioned between the 'LOW FLEX' and 'HIGH FLEX' scenario. This scenario assumes that a facilitating market design is quickly and fully adopted and work is undertaken to address the barriers standing in the way of new flexibility participating in the system. However, this scenario assumes that these changes will take time to occur, and market imperfections and some barriers will not be immediately lifted.*

4. *A 'CENTRAL-' scenario which represents the evolution of the reserve needs if slower and insufficient progress is made on the uptake of end user flexibility. Elia will need to perform an upward revision of its projections if this scenario materializes.*

The scenarios are based on assumptions related to market performance indicators, representing the ability of the market to balance forecast errors. Forecast accuracy improvements are fixed at 1% per year, except for the worst case ('LOW FLEX') scenario where it is set at 0%. The chart on the left-hand side of Figure 103 shows the evolutions in system imbalance over time for the four scenarios: it represents improvements to the system imbalance in percentage terms compared with the previous year, considering the same amount of installed generation (iteratively taking into account new renewable capacity added to the system over the previous years). This represents evolutions in the assumed ability of market players to balance the installed capacity. The chart on the right-hand side of Figure 103 shows the evolution of the BRP coverage, e.g., the ability of market players to cover forecast errors related to new renewable capacity. It represents the percentage of the corresponding forecast errors related to new capacity which is covered by the market while the remaining share contributes to the system imbalance.

Note that large system imbalances were observed in 2021 and 2022 related to the energy crisis years and to the challenge in terms of the visibility of market players connected to the generation of decentralized capacity. For 2024, the scenarios differ in the speed of recovery after the crisis and the uptake of solutions to improve the visibility of decentralized generation. After 2024, scenarios depend on the speed of improvements to the market design and addressing other barriers standing in the way of the participation of end user flexibility. The lower coverage for offshore in the "CENTRAL" and "CENTRAL-" scenarios relates to ongoing investigations to determine the assumptions related to the degree of BRP coverage of offshore wind forecast errors. Note that the assumptions taken are also based on the hypothesis that new capacity, including new offshore wind, is subject to balancing responsibility and corresponding incentives.

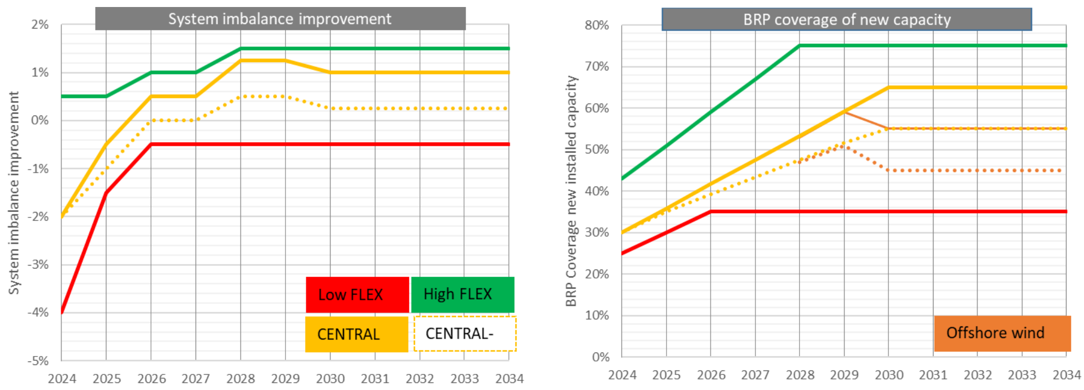


Figure 103 : Evolution of the market performance indicators used for the system imbalance projections 2024-2034

- **Observed LFC block imbalance trends**

Figure 104 depicts the yearly evolution of the absolute values of the LFC block imbalance between 2011 and 2023 (until mid-July 2023) and the increase (deterioration) or reduction (improvement) is expressed as percentage of the previous year:

- results show that since 2016 (latest 8 years), a yearly average increase of the absolute average value of 1.3% was observed. A similar evolution is observed for the largest imbalances where an average increase of 3.5% was observed;
- results show that since 2019 (latest 5 years), a yearly average increase of the absolute average value of 1.5% was observed. A similar evolution is observed for the largest imbalances where the average increase of 3.2% was observed;

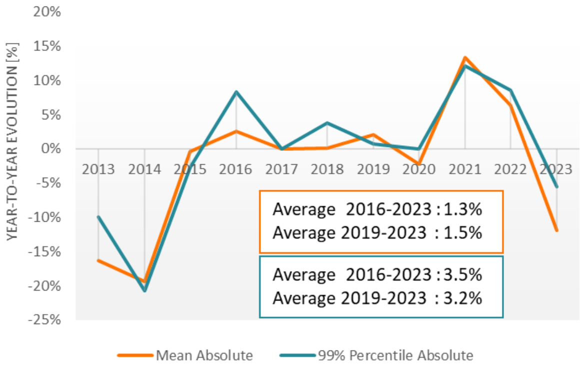


Figure 104 : evolution of the Mean Absolute and 99% Percentile Absolute LFC block imbalance expressed as the increase (+) / decrease (-) expressed as percentage of the previous year

Based on these results a yearly deterioration of the general LFC block imbalances -4.0% was taken as starting point for 2022 in all scenarios. These are assumed to:

- improve slowly towards -0.5% towards 2026 in a LOW FLEX scenario;
- improve rapidly towards 1.0% towards 2026 and even 1.5% towards 2028 in a HIGH FLEX scenario;
- improve to 0.0% and 0.5% in 2026 and 0.5% and 1.3% in 2028 for the CENTRAL- and CENTRAL scenario, respectively. A reduction of the market performance to 0.3% and 1% is assumed with an offshore bidding zone compare to the existing generation fleet following reduced reactive balancing opportunities in an offshore bidding zone.

With its continuous efforts to provide the market with the right tools and incentives to balance their portfolio, Elia aims to improve LFC block imbalance quality in all scenarios despite the challenges of the energy transition.

- **Observed ability of BRPs to balance their portfolio**

The ability for BRPs to deal with offshore generation in their portfolio depends on various things. Important is the access of individual BRPs to flexibility. As shown in the previous study, this ability can vary from BRP to BRP but on average, this is only expected to improve in the future by means of better access to markets and better price signals in line with the presented scenarios. Note that the flexibility is also not necessarily to be found physically in the BRP's portfolio but can also be accessed via intraday markets and trough reactive balancing (where BRPs help to balance the system by activating flexibility in their portfolio reacting on imbalance settlement prices).

A first indicator which is used to build the scenarios on LFC block imbalance projections are the intraday forecast updates, e.g., the evolution of the forecast error when going from the day-ahead to the last forecast. These indicators can be calculated by means of historic observations. The literature shows that the relative theoretical improvement potential of an intraday forecast compared to a forecast on D-1 is in the range of 30% to 40% maximum. Based on observations of Elia's forecast tools and offshore wind power nominations in 2020-21,

Figure 105 shows that this improvement finds itself at the lower end with 20% to 30% improvement. This is lower than observed in the previous study for 2018-19 which seems to be due to better day-ahead forecasting. Note that for offshore, it is more representative to look at the nominations than at the Elia forecast tool due to known forecasting issues in this period.

However, with improving liquidity on intraday markets, it is assumed that BRPs can adapt their position in function of this forecast update. Note however that with increasing renewable capacity, these forecast errors, generally expressed in percentage, require increasing volumes of flexibility, generally expressed in power.

2020 - 2021	Mean Absolute Error Day-ahead	Mean Absolute Error Last Forecast	Intraday forecast improvement
Offshore	11,0%	9,0%	17,8%
Offshore Nom.	7,9%	6,0%	23,9%
Onshore	4,1%	2,8%	30,9%
Photovoltaics	1,6%	1,2%	24,6%

Figure 105 : Forecast error statistics for year 2020 and 2021 (Elia forecast tools and offshore wind power nominations)

It is to be noted that additional analyses in the MOG 2 system integration, focusing on the system imbalance and market positions during unpredicted offshore wind power variations, and in particular largest variations which have the most impact on the larger LFC block imbalances relevant for reserve dimensioning, have already confirmed that there are positive correlations between the forecast errors and the BRP imbalances.

The intraday forecast improvement and additional analyses on the behavior of the system imbalance during periods with large forecast errors justify the BRP coverage starting point of around 30%. Concerning the projections, the BRP coverage is expected to improve in all scenarios in line with the scenarios presented above.

5.5.4. Reserve capacity projections

Based on the projections of system imbalances for 2024 and 2034, projections are made on the FRR, aFRR and mFRR needs. These needs are calculated based on the current dynamic dimensioning method applied by Elia on a daily basis to determine the reserve needs, while the aFRR needs are determined based on the methodology which is approved to be implemented in Q4 2024[30]. Figure 106 (upper left), the projections for upward FRR needs show that average reserve levels can:

- increase from around 1100 MW in 2024 to around 2,200 MW in 2034 in the LOW FLEX scenario;
- increase from around 1060 MW in 2024 to around 1,360 MW in 2034 in the HIGH FLEX scenario;
- increase from around 1090 MW in 2024 to around 1,660 MW in 2034 in the CENTRAL scenario;
- increase from around 1090 MW in 2024 to around 1,850 MW in 2034 in the CENTRAL- scenario.

This means that the average reserve needs can increase with a factor 2 compared with today's FRR levels (around 1,040 MW), following the penetration of variable renewable generation in a 'worst case' LOW FLEX scenario. Projections show that offshore wind developments have a prominent effect between 2029 and 2030. It is also confirmed that in a best 'HIGH FLEX' scenario, this reserve capacity increase towards 2034 can be limited to a factor 1,3. As indicated above, Elia considers the CENTRAL scenario as its best estimate scenario. If the upcoming evolutions indicate that market design improvements or solutions to identified barriers do not progress as foreseen, Elia will shift its best estimate towards a CENTRAL- scenario, closer to the LOW FLEX scenario.

[30] *More info on Elia website: https://www.elia.be/en/electricity-market-and-system/system-services/keeping-the-balance*

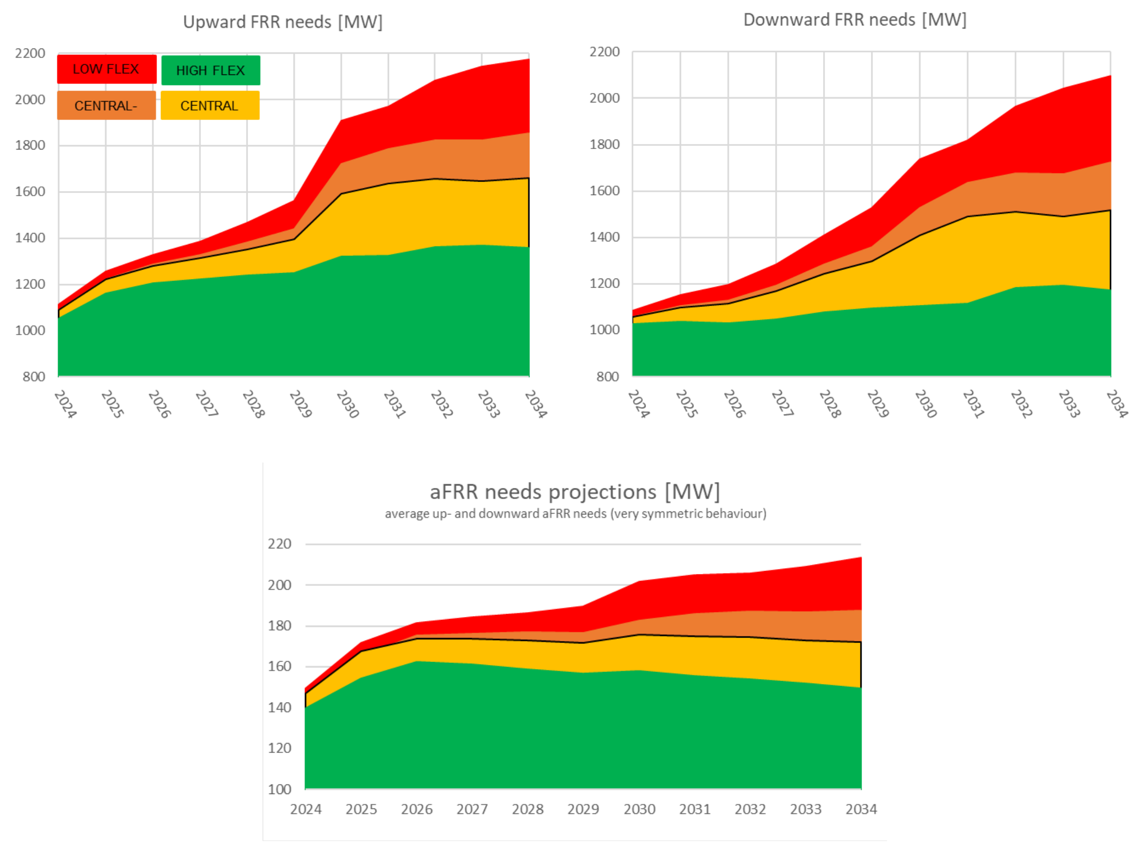


Figure 106 : FRR and aFRR reserve needs projections

The projections for downward FRR needs (Figure 106, upper right) show that average reserve levels can:

- increase from around 1090 MW in 2024 to around 2,100 MW in 2034 in the LOW FLEX scenario;
- increase from around 1030 MW in 2024 to around 1,170 MW in 2024 in the HIGH FLEX scenario;
- increase from around 1060 MW in 2024 to around 1,520 MW in 2034 in the CENTRAL scenario;
- increase from around 1060 MW in 2024 to around 1,750 MW in 2034 in the CENTRAL- scenario.

The downward reserve needs projections in the run-up to 2034 are found to behave in a similar way to the upward reserves, although the reserve needs are slightly lower as downward reserve needs are less impacted by forced outage risks. While forced outage risk of generators only impact the upward reserve needs, outages of HVDC interconnectors can impact the downward reserves when losing the cable when scheduled in energy export. Note that this asymmetry between the upward and downward FRR needs is lower in the LOW FLEX scenario, since the forced outage risks of generators have lower weight compared to the prediction risks of renewable generation.

As demonstrated in the MOG 2 system integration study by comparing a scenario with and without additional offshore wind energy, offshore wind power has an impact on the reserve capacity needs. This is also confirmed in this study by means of the incremental FRR needs between 2028 and 2030. However, no specific assessment is made of the impact of additional offshore wind power in this study. Reserves are assessed for all renewables and outages together and there is no specific value in analyzing the impact of individual drivers under current legislation (cf. Article 157 of the SO Regulation). Instead, it is considered more useful to focus on managing this reserve capacity needs increase and it particular the cost of balancing capacity procurement.

While the results in the previous paragraphs focus on the average reserve needs, Figure 107 details the expected behavior of the dynamic reserve needs following the simulations. Note that these results originate from the Q4 2022 simulation run (before updating the renewable generation profiles with the latest ambitions communicated by the government begin 2023) but this is not expected to have a significant impact except for 2028 which already assumes 700 MW of additional wind power installed and therefore will overestimate the reserve needs.

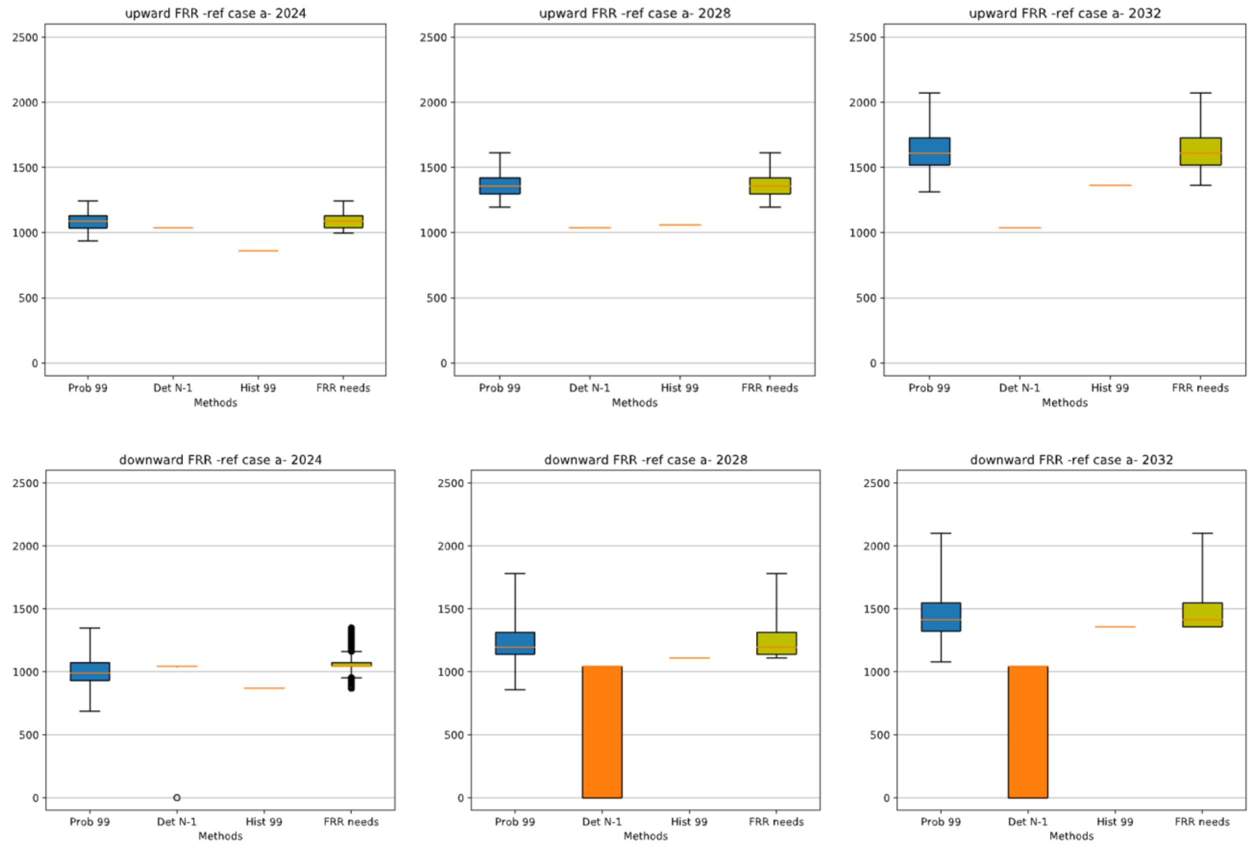


Figure 107 : box plots of the FRR needs results and the methodology components (PROB99, DET N-1, HIST99) in 2024, 2028, 2032

It is shown that, until 2028, the upward FRR needs are, in contrast to today, more and more driven by the probabilistic result (PROB99) while the minimum threshold (DET N-1) set by the dimensioning incident still plays a substantial role. The legal threshold (HIST99) does not play any role. However, towards 2032, the dimensioning incident becomes irrelevant with the increasing probabilistic results. The legal threshold becomes a constraint as well, flooring minimum values as well as limiting the reserve sharing potential constrained by the difference between the DET N-1 and the HIST99.

The same trend is observed for the downward FRR needs where similar trends are observed. The dimensioning incident remains relevant after 2024, although to less extent with increasing probabilistic results, as well when the dimensioning incident is 0 MW when predicting the Nemo Link in import (or considering the asset as unavailable). The HIST99 floors the minimum needs. Towards 2032, the dimensioning incident becomes irrelevant as well and the HIST99 will floor the reserve needs. It is important to note that these represent the results of the CENTRAL scenario, being Elia's best estimate. Results of a HIGH FLEX scenario will result in lower probabilistic results, and therefore increase the role of the dimensioning incident again.

In line with the system imbalance projections and general FRR needs evolutions, aFRR needs are expected to increase from around 140 - 150 MW in 2024 (this increase compares to the current aFRR needs of 117 MW and is explained amongst other factors by an expected increase in the targeted balancing quality by European TSOs). Depending on the scenario, these volumes may increase in the NO FLEX scenario to 210 – 220 MW in the lead-up to 2034 or return to 150 MW within the same timeframe (after a temporal increase of 160 MW from 2026 onwards) in the HIGH FLEX scenario. In the CENTRAL scenario, these volumes are assumed to evolve towards 170 MW. Note that the aFRR needs are calculated separately for upward and downward directions, but as the difference is generally small, the projections are represented by the average of the upward and downward results. Note that the mFRR reserve needs are calculated as the difference between the FRR needs and the aFRR needs.

5.5.5. Balancing capacity procurement

In 2022, Elia presented its methodology to stakeholders for accounting non-contracted balancing energy bids on mFRR from 2027 onwards. This will be based on a machine learning forecast of the available mFRR balancing energy bids which are not related to upfront procurement for the next day. The effect on balancing capacity procurement is therefore expected to be felt from 2028 onwards. Based on the same timeline, Elia has proposed to investigate dynamic approaches for accounting for cross-border flexibility (through reserve sharing). Together, these evolutions are expected to result in the following:

- mFRR reserve sharing volumes of up to 250 MW / 350 MW for upward and downward capacity respectively in the lead-up to 2027, increasing to 300 MW / 350 from 2028 onwards through the implementation of dynamic sharing methodologies;

- based on dynamic and partial procurement strategies in the HIGH FLEX and CENTRAL scenarios, partial procurement strategies allow the mFRR balancing capacity procurement to be gradually reduced by forecasting available non-contracted balancing energy bids and subtracting these from the needs;
- an assumption that downward flexibility can remain covered without downward procurement of mFRR balancing capacity.

Figure 108 depicts the up- and downward balancing capacity to be procured under each scenario. These assumptions remain subject to many uncertainties. While Elia's Adequacy and Flexibility Study indicated an increasing availability of fast flexibility means (reaction in a few hours down to 15 minutes), this does not translate in a one-to-one manner to available non-contracted balancing energy bids and depends largely on the ability to comply with product characteristics of mFRR, as well as relieving the barriers for new flexibility delivered by end users to actively participate in balancing markets. The contribution of cross-border flexibility depends on liquidity in the mFRR balancing energy platform, while reforming the regulatory, or even legal framework, to fully account for cross-border flexibility in the local dimensioning of balancing capacity. Elia investigated a methodology to account for non-contracted balancing energy bids in mFRR dimensioning and presented a specific implementation plan in the lead-up to 2027.

Based on the results of the available ramping flexibility (reaction within 5 minutes), similar conclusions could also be drawn for aFRR needs. However, no plans exist at this point in terms of the implementation of methods allowing to account for non-contracted aFRR balancing energy bids.

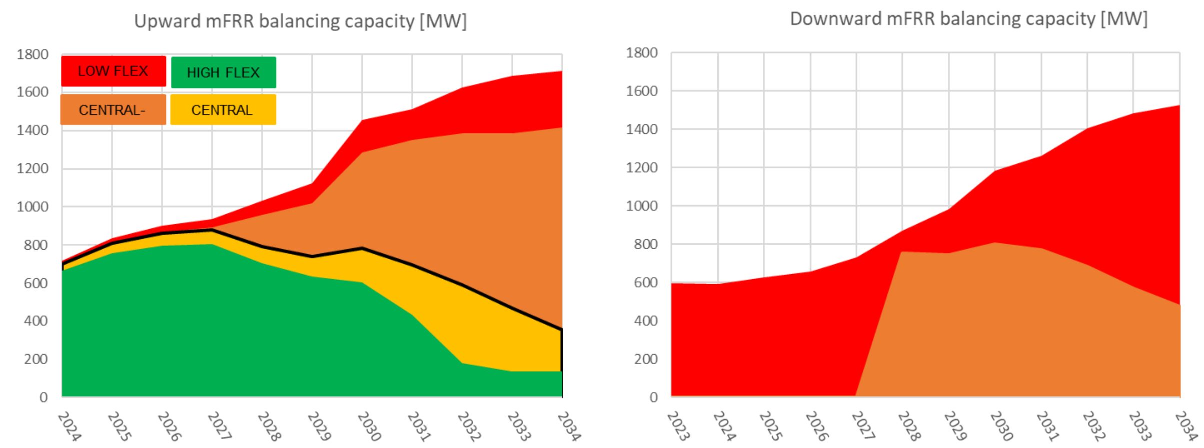


Figure 108 : Expected upward and downward mFRR procurement

5.5.6. Conclusions

This study updates the projections of Elia's FRR reserve requirements (FCR remains outside the scope of this study as dimensioned on continental level and not expected to be impacted by the foreseen Belgian offshore developments) following the integration of additional offshore wind power, and variable renewable generation in general. Besides the scenarios concerning Belgium's generation fleet, this is based on the ability of the market players to deal with future portfolio and system imbalances caused by offshore wind power, as well as with other variable renewable prediction errors and variations and forced outages of generation and transmission assets.

It is important that under the current infrastructure design proposals, no impact as such is identified through the dimensioning incident, i.e. the largest outage in the system which determined the minimum reserve capacity needs under all conditions. This is due to the design choices increasing the redundancy of the equipment.

In contrast, the probabilistic results confirm the increasing upward (downward) FRR reserve capacity needs towards 2030 in all scenarios:

- To 1910 MW (1740 MW) in LOW FLEX scenario
- To 1320 MW (1100 MW) in a HIGH FLEX scenario
- To 1590 MW (1410 MW) in the CENTRAL scenario, e.g. Elia's best estimate.

The focus of Elia is on the management of this increase in general, rather than on isolating the impact of offshore wind power. While it is possible to determine the impact of offshore wind power (as shown in the MOG 2 2020 study) through sensitivities this is not very relevant as reserve capacity needs are determined by all drivers together, based on observed system imbalances following SO Regulation. Nevertheless, the impact of offshore is relatively clear following the substantial increase in needs between 2028 and 2030 with an increase of upward FRR capacity needs with 440 MW (LOW FLEX), 82 MW (HIGH FLEX) and 238 MW (CENTRAL) and downward FRR capacity needs with 328 MW (LOW FLEX), 26 MW (HIGH FLEX) and 165 MW (CENTRAL). This translates mainly to mFRR needs while aFRR needs are expected to increase with almost 20 MW (to around 200 MW) in the LOW FLEX scenario and remain stable (at around 155 MW) in the HIGH FLEX scenario. These capacities are used in the system simulations as specified in Section 5.6 to determine the need for mitigation measures to deal with exceptional balancing conditions following offshore storm and ramping events.

Note that Elia's has the ambition to manage increasing reserve capacity needs without additional balancing capacity procurements by means of implementation of its dynamic procurement roadmap, forecasting available local and cross-border non-contracted balancing energy bids in the system for the next day and procuring only upfront the missing energy as balancing capacity. This will nevertheless require substantial efforts in the development and participation of new flexibility in the system, as well under form of reactive balancing (through BRP portfolios) as balancing energy bids (through explicit bids).

As further discussed in Section 5.8, Elia does not expect a fundamental impact of creating an offshore bidding zones on reserve dimensioning and balancing capacity procurement. While reserve capacity needs may slightly increase following lower reactive balancing opportunities for the BRPs in the offshore LFC Area (taken into account in the reserve projections), this should not impact the available flexibility offered in the EU balancing platforms through explicit bidding. Potential geographical constraints can be taken into account in the dimensioning methodology but are expected to not play a major role as:

- shortages in the Offshore Bidding Zone free up capacity on the cable and can under normal conditions always be balanced by activating balancing energy in the Belgian LFC area (complementary to potential access to the connected balancing markets);
- excess in the Offshore Bidding Zone can always be managed by wind power control through explicit balancing energy bids or other control measures (complementary to potential access to the connected balancing markets).

5.6. Impact on Elia's system operations

This section aims to evaluate the real time system operation impact of increasing the installed offshore wind power capacity from 2.3 GW to 5.8 GW. The assessment builds on the results presented in previous sections concerning the expected offshore generation profiles, as well as on system evolutions with respect to available flexibility in the system facilitated through Elia's reserve capacity.

Section 5.6.1 provides an overview of the methodology used for the system simulations and the evaluation criteria with which the results are assessed. Section 5.6.2 discusses on the most important assumptions in the modelling : (1) the minimum flexibility available during balancing events (ensured by available FRR), (2) the ability of market players to balance their portfolio during a storm or ramping event, and finally (3) the activation characteristics of the reserves. Section 5.6.3 validates the model by means of analyzing step-by-step the impact of the assumptions compared trough the previous study. Finally, the results of the simulation events are presented and analyzed in Section 5.6.4 taking into consideration the scenarios and sensitivities with conclusions in Section 5.6.5.

Note that the scope of the system simulations is limited to storm and ramping events. These are defined as:

1. Ramping events (below wind speeds of 20 m/s): sudden variation of wind power generation as a result of wind speed variation related to the exponential profile of the power curve at normal wind speeds.

2. Storm events (above wind speeds of 20 m/s): sudden variation of wind power generation due to cut-out / cut-in behavior of wind turbines in case of elevated wind speed related to high wind speed management systems of turbines.

5.6.1. Methodology

The methodology is based on a deterministic approach where the objective of the model is to evaluate the impact of a given event on real-time system operations. The analyses below do not take into account any mitigation measure or specific restriction yet, however some sensitivities have been performed to assess the impact of the recommended mitigation measures. These impact assessments are discussed in Section 5.7.

5.6.1.0 Selection of events

The Technical University of Denmark (DTU) has provided simulations for different scenarios of installed offshore wind farms in the Belgian North Sea. These simulations include the power output of existing and new offshore wind farms in resolutions up to five minutes for a horizon of 40 years.

For each scenario of installed offshore capacity (2.3 GW, 3.0 GW, 4.4 GW and 5.8 GW), DTU has defined sets of storm and extreme ramping events, based on observations in 40 years of simulation data. Furthermore, the frequency of occurrence and other important characteristics of these events are also available. A focus is put on a selection of ramping and storm events for 4.4 GW (for comparison with the previous study) and 5.8 GW (current scenario for wind power developments in Belgium towards 2030) scenarios that are used in the study as an input to the real-time impact assessments. Note that the 4.4 GW scenario is only used to allow the comparison of the results in this study with the outcome of the previous study presented in the MOG 2 system integration study of 2020.

► **Selection of ramping events**

Extreme ramping events are high increase (or decrease) in power output over a limited time period. The analysis focuses on three types of ramping events, as provided by DTU, namely:

- 5-minute ramping events;
- 15-minute ramping events;
- 60-minute ramping events.

A database containing a collection of such ramping events, classified based on the generator, shut down technology and the power ramp (over 5, 15 and 60 minutes) is used. Based on these dimensions, specific events have been selected representing the different cases to be analyzed. The data for any given case consists of a timeseries with a resolution of 1 minute.

A selection of eight events is identified from the 60-minutes ramping events database, complemented with the 15-minute ramping events, to select events with fast variations. The analysis was performed only using data sets considering wind turbines of technology type ‘TECH B’. This will result in higher wind power variations compared to ‘TECH A’ due to the steeper power curve profile at normal wind speeds. The selection of assumptions resulting in the largest variations is justified by Elia to be able to ensure system security in every feasible scenario.

► **Selection of storm events**

Storm events result in a decrease of power output due to the wind speed exceeding the cut-out speed of wind turbines. A storm event is characterized by a cut-out (shut down of the turbines) phase followed by a relative stable power output, at 0 MW, and a cut-in phase (re-activation of the turbines). The analysis mainly focuses on extreme storm events with very high wind speeds resulting in a high or total cut-out of the offshore wind farms.

Similarly, to the ramping events, a selection of eight events with maximum power deviation during the storm as well as longer periods of cut-off are used for the purpose of the analysis. The analysis performed focuses on the 25m/s – direct cut off shutdown technology of wind turbines, to observe the violation durations without any mitigation measure.

5.6.1.1 Simulation model

A simulation model has been developed to simulate the reaction of the system on ramping or storm events using three categories of assumptions (Figure 109):

(1) available balancing energy, representing the minimum flexibility available during balancing events trough Elia’s available FRR reserve capacity;
(2) the BRP reaction, representing the ability of market players and corresponding BRPs to balance their portfolio during a storm or ramping event; and
(3) the FRR reserve capacity activation process, representing the activation of available aFRR and mFRR balancing energy bids.

The aFRR activation process takes into account imbalance netting with other regions, the availability of aFRR balancing energy bids, reserved and non-reserved. The mFRR activation process takes into account the mFRR balancing energy bids, reserved and non-reserved, as well as available sharing capacities with other regions.

The simulation model results in two principal outputs:

1. 'Contribution to the System Imbalance (SI)[31]'is defined as the difference between the change in power output of the offshore wind farms and the reaction of respective BRPs (meaning that the rest of the system is assumed to be balanced);
2. 'Area Control Error (ACE)[32]' defined as the difference between contribution to the System Imbalance and Net Regulating Volume, representing the Balancing Energy activated by the TSO.

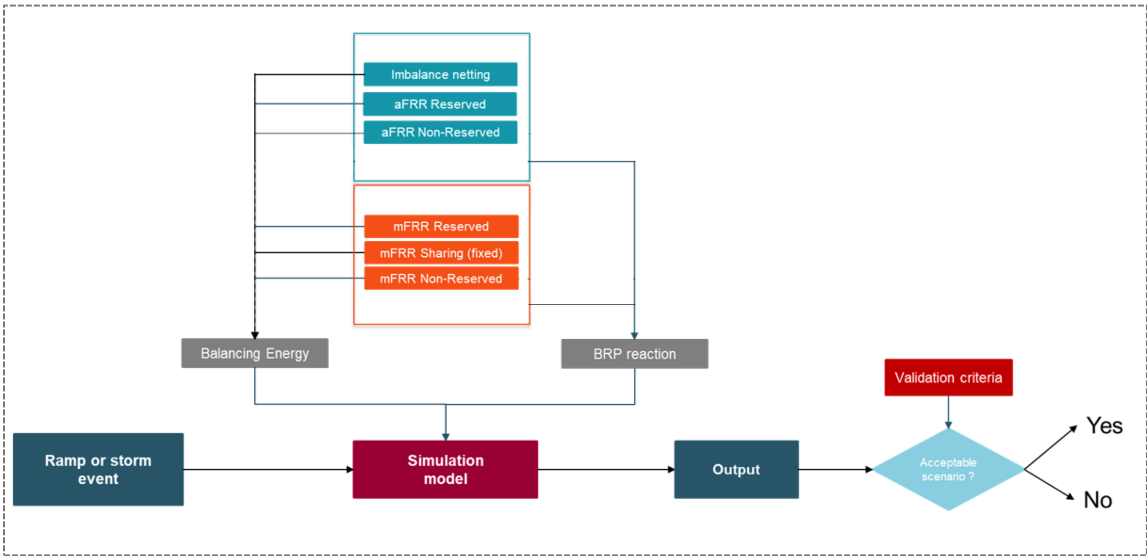


Figure 109 : Schematic representation of the simulation model used for analysis of impact on real-time system operations

The output of the model is a remaining area control error, representing the shortage or excess following the storm which could not be managed by the market or Elia. This results in unscheduled exchanges with other regions and is of course to be avoided. The simulated behavior of the ACE is then used to analyze the duration of violations durations in each of the different cases.

5.6.1.2 Validation criteria

In order to validate whether a simulated ramping or storm event can be considered as acceptable in terms of impact on real-time system operations, specific validation criteria on the maximum acceptable ACE and duration of the ACE have been defined in the context of this analysis. These validation criteria are based on requirements of SO Regulation, as well as operational agreements between TSOs. These

[31] *Also referred to as LFC block imbalances*

[32] *Also referred to as FRCE (Frequency Restoration Control Error)*

will be used to assess the severity of outcomes and thus the potential need in term of mitigation measures:

- article 18.2 of SO Regulation indicates that the Continental Europe Synchronous Area goes into alert state if the frequency deviation is higher than 50 mHz for 15 minutes or higher than 100 mHz for 5 minutes;
- article 18.3 of SO Regulations states that the Continental Europe Synchronous Area will go into emergency state if the frequency deviation exceeds 200 mHz.

In order to convert this into an ACE based criteria for the Elia control area, it is considered that Elia should not be responsible for more than 25% of the deviation in the nominal frequency of the synchronous area. This ratio is significant compared to the size of the Belgian LFC block, which is somehow reflected by the ratio of the FCR obligation of Belgium which is around 80 MW of the total volume of 3000 MW needed for the overall continental synchronous area. The 25% threshold is reflected as well in the Article 152.13 of SO Regulation, which indicates that a participation of more than 25% to the total deviation for more than 30 consecutive minutes needs to be avoided. The validation criteria are defined to avoid the occurrence of such events.

With the above principles and considering a regulating power factor of the continental system of 30000 MW / Hz (this means that a deviation of 3000 MW leads to a frequency deviation of 0.1 Hz or 100 mHz), the frequency deviation from SO Regulation can be converted into an ACE of the Elia control zone. This means that:

- a frequency deviation higher than 50 mHz for 15 minutes corresponds to an ACE higher than 375 MW for 15 minutes, which should be assimilated to an alert state. A frequency deviation higher than 100 mHz for 5 minutes becomes an imbalance higher than 750 MW for 5 minutes, which should as well be assimilated to an alert state;
- a frequency deviation higher than 200 mHz (for any duration) becomes an ACE higher than 1500 MW, which should be assimilated to an emergency state;
- coming back to Article 152.13 of SOGL, we can also state that the imbalance of the Elia control area cannot exceed 25% of the reference incident of continental Europe (which is 3000 MW) for 30 minutes. So, the imbalance of the Elia control zone cannot exceed 750 MW for 30 minutes without entering in emergency state.

Status indicator:

Following the above SO Regulation articles, the validation criteria are differentiated in function of the severity which is done by means of a color indication as in the EAS (Emergency Awareness System) in Figure 110:

1. Green zone - Normal state: it represents the normal situations and all acceptable cases;
2. Yellow zone - Alert state: the yellow zone represents a violation of the criteria and implies that the extraordinary procedure for frequency deviation would be launched, which requires all TSOs to take action to reduce the frequency deviation;
3. Red zone - Emergency state: The red represents a violation of the criteria and could trigger load shedding (depending on the observed frequency at that time) and thus to be avoided at all times.

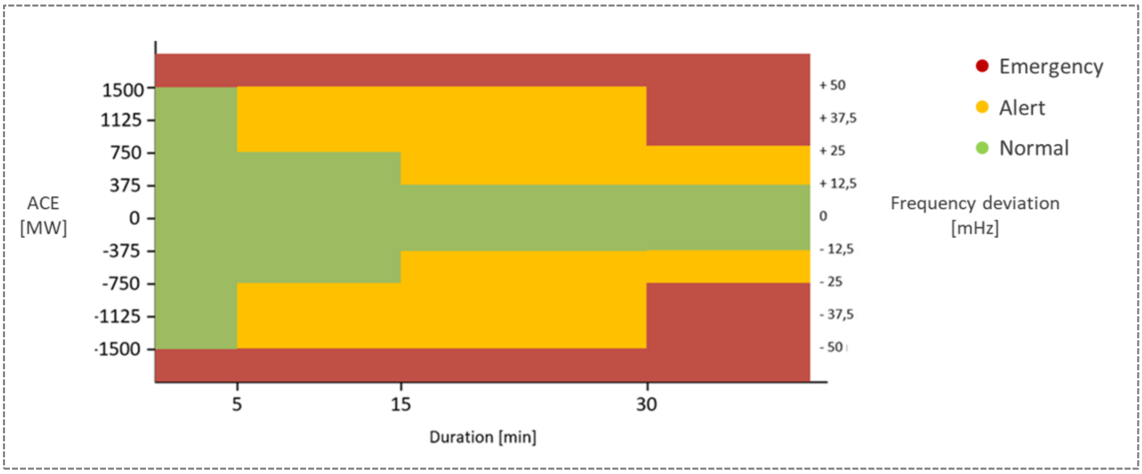


Figure 110 : Graphical representation of the validation criteria

5.6.2. Assumptions

5.6.2.1 Available reserve capacity during storm and ramp events

As explained in the Section 5.6.1, the methodology takes into account available flexibility in the system through balancing energy bids. Total flexibility in the system depends on many elements and is made available by the market (through intraday market and portfolio balancing) and by the TSO (through reserve capacity). While the market flexibility is captured in the simulations through the BRP reaction (discussed in Section 5.6.2.1), the available balancing energy is based on projections of Elia's FRR reserve capacity. It can be seen as the minimum flexibility in the system ensured by the TSO following dimensioning methodologies in line with the legal requirements and after regulatory approval. This includes aFRR and mFRR. Note that the framework of Elia's reserve projections is discussed in Section 5.5.

Figure 111 gives an overview of the available reserve scenarios. A first simulation is based on minimum flexibility (referred to as Case 1). The available FRR is aligned with the upward FRR reserve capacity in the HIGH FLEX scenario, e.g., around 1300 MW in 2030. Note that in a HIGH FLEX scenario, the ability of market players to balance their portfolio during normal system conditions is high and Elia's reserve capacity needs remain therefore low. Note that the available aFRR in every scenario remains aligned with Elia's CENTRAL scenario (which is Elia's best estimate), i.e. around 180 MW in 2030. Note that:

- the downward FRR needs are lower in a best case scenario, i.e., around 1100 MW;
- the aFRR needs are lower in a best case scenario, i.e., around 160 MW;
- available flexibility can in theory be lower following dynamic dimensioning methods for FRR and aFRR, determined on the predicted imbalance risks in the system. Nevertheless, it is not deemed likely that these will be lower during periods with potential storm or ramping events, typically characterized by high wind.

Case 2 is characterized by additional mFRR availability and is approximatively aligned with the CENTRAL scenario, around 1500 MW in 2030. As the CENTRAL scenario is Elia's best estimate, one could say that case 2 might be the most representative in terms of minimum flexibility. Also note here that the upward FRR in the CENTRAL scenario is slightly higher, i.e., around 1600 MW and the downward FRR is slightly lower, i.e. around 1400 MW. This means that the system violations might be slightly overestimated in upward direction, and slightly underestimated in downward direction[33]. The estimations and sensitivities should be used to map best estimate minimum reserve capacity on the conducted sensitivities, in this case 2.

Reserve scenario	FRR [MW]	aFRR [MW]	mFRR [MW]
Case 1	1300	180	1120
Case 2	1500		1320
Case 3	2000		1820
Case 4	2500		2320

Figure 111 : Assumptions on the available FRR in the system

Case 3 and 4 assume increasing mFRR availability through non-contracted balancing energy bids in the European balancing energy platform (Mari) with an assumed total FRR of 2000 MW and 2500 MW respectively. This is not unrealistic as additional cross-border flexibility will become available as such through the European balancing platform Mari as from 2024. Nevertheless, liquidity on these platforms

[33] *The minor differences with the cases presented and the scenarios is explained by the fact that final calculation of the reserve capacity projections were finished after the system simulations were already conducted. Both tasks were conducted in parallel to reduce the lead time of the study.*

are subject to large uncertainty and one should realize that storm and ramping events are likely correlated with neighboring systems which justify to be cautious when interpreting these results.

Note that in the previous study, a sensitivity analysis was conducted by adding additional volumes of aFRR to selected cases. This is related to the availability of imbalance netting or additional non-contracted balancing energy bids through Picasso. This sensitivity was found to have a positive effect on system violations but is not re-conducted following the uncertainty on liquidity. Furthermore the mitigation measures need to be robust for worst case conditions, which justifies taking a conservative assumption not taking into account additional aFRR volumes.

5.6.2.2 Balancing market performance during storm and ramp events

The balancing market performance is reflected in the system simulation model by means of three indicators:

- **Coverage [%]:** represents the part of the increase or reduction in power generation covered by the market. It relates to how a decrease or increase in offshore wind power translates into a system imbalance.
- **Coverage gradient** [%/min]: represents the rate with which the market reacts to cover power variations. It relates to how fast an offshore wind power variation translates into system imbalance variations.
- **Full Recovery Time** [min]: represents the time needed for BRPs to fully cover the system imbalance in a stable way. It relates to how long it takes to return the system imbalance to 0 MW after an offshore wind power variation.

It is important that the methodology to determine these indicators is improved compared to the previous study considering a set of recent events. While the indicators were based on a few best and worst case examples of system imbalance behavior during storm and ramping, a methodology is put in place to calculate the above-mentioned indicators based on all storm events and for 6 to 7 of the largest non-storm related ramp events per year. The values are based on observations during storm periods and largest ramping events over a period from the start of 2020 until Summer 2022. This only relates to events after the commissioning of the full 2.3 GW wind power. The results are shown in Figure 112.

Assumptions for 5,8 GW	Down Ramping event (shortage)			Up Ramping event (excess)			Storm cut-out		
	Coverage	Full recovery time	Gradient	Coverage	Full recovery time	Gradient	Coverage	Full recovery time	Gradient
Best case	60%	45 min	3,0%	80%	15 min	3,0%	85%	15 min	3,0%
Worst case	30%	120 min		50%	120 min		45%	120 min	

Performance compared to MOG 2 (2020) assumptions: Equal performance / Better performance

Figure 112 : Balancing market performance assumptions

The balancing market performance indicators for the **storm cut-outs** are all higher or at least equal compared to the previous study. The best case performance is based on the best average coverage observed (storm Eunice in 2022 and Christoph in 2021). The worst case is based on the worst average coverage observed (storm Dennis in 2020). The full recovery time is based on the average of the yearly maximum and minimum duration the period 2020-2022 while the gradient is based on the average gradient over the same period.

The **downward ramping events during storms and other events** are observed to be higher or equal than in the previous study. The worst case and the best case coverage are based on the average of the yearly maximum and minimum over the period 2020-2022 while the gradient is based on the average gradient over the same period. Note that that no improvement is observed for the worst case compared to the previous study. The behavior during downward ramping events is very asymmetric to the upward direction where performance is not assumed to be much higher (which was not taken into account in the previous study as not split was made between upward and downward ramping events). This observation follows the fact that wind power can react on excess energy by means of self-curtailment.

Update of balancing market performance based on latest observations until Summer 2023

Note that on request of some stakeholders during the Task Force discussions, Elia conducted an update of its original analysis (until Summer 2022) with observations until Summer 2023. It is first concluded that no new storm events were registered between Summer 2022 and summer 2023. Values are therefore maintained on best and worst market performance observed (average performance over the duration of the storm). No obvious positive trends in market performance are observed during the latest 3 years (large variations in behavior or storm, predictability, and system impact).

The analysis was however extended with largest up- and downward ramping events in the second part of 2022 and first part of 2023. The update confirms that base case market performance during upward ramping events should be improved to 90% (as confirmed by reprensatives of the offshore sector during the Task Force discussions). Nevertheless, the worst case assumptions is maintained at 50%, based on the yearly average of the minimum performance between 2020 and mid-2023. As the mitigation measures are based on the worst case conditions, no impact of increasing the performance to 90% is therefore expected on the conclusions of the study. Market performance assumptions on the downward ramping events are confirmed (yearly average of the minimum and maximum performance).

Note that the average gradient over different type of events is confirmed and varies between 2,8% and 3,7%, and is therefore maintained at 3,0% for reasons of simplification.

In general, it is noted that the best case events relate to well forecasted events, while worst case events relate to badly forecasted events. Furthermore, it is noted that no clear positive evolution is observed over time neither for storms or ramps. It is however not easy to draw such conclusions as the performance depends on many aspects such as the predictability, the behavior of the event and the general conditions in the system such as the availability of flexibility in the system. Nevertheless, by lack of better information, it is assumed that these market performance indicators will prevail towards 2030.Market performance levels are thus kept equal to current observations and therefore assume that absolute performance is increased to maintain the same relative performance in view of adding 3.5 GW of offshore wind power. In other words, these balancing market performance indicators already assume a substantial improvement in predictability and flexibility in the system to allow market players to maintain balancing performance with additional offshore wind power. Note that in contrast, market performance during normal conditions, used for the reserve projections (Section 5.5.3.3), are assumed to improve, at least in Elia's best estimate and high flexibility scenarios.

5.6.2.3 Activation characteristics of reserves

This section specifies the assumptions on reserve activation in the simulation model. It includes several improvements compared to the MOG 2 system integration study.

Firstly, the aFRR controller is tuned to larger aFRR activation volumes (larger than the contracted volume). In addition, the foreseen 5 min Full Activation Time (FAT) for all aFRR reserves activation is taken into account, using Merit Order List activation sequence in line with the new foreseen design evolution linked with the connection to Picasso. The mFRR activation logic is improved to capture better operator decisions (direct / scheduled activations) following the foreseen design after connection to the European balancing energy platform (Mari).

Secondly, the modelling dependence between frequency and system imbalance is improved by taking into consideration more up to date figure on k-factor characteristics. It is important to note that the study is based on system imbalances and area control errors resulting from offshore wind (compensated by assumptions on available flexibility) only. The rest of the system is assumed to be balanced.

No fundamental impact on the model is expected when considering an offshore bidding zone. No major impact is assumed on system imbalance if wind power is connected through DC or AC.

The uncertainty on available reserve capacity, BRP ability and topology evolution are captured through sensitivity analysis (cf. Section 5.6.2.1 and Section 5.6.2.2).

5.6.3. Validation

The philosophy for validation considers a selection of eight events tested against thirty-two combinations of sensitivities. This results in a total of 256 simulations. The combinations correspond to the type of the events (storm and ramping events), the direction of the event (upward and downward), the market performance (best and worst) and the available FRR (1300 MW, 1500 MW, 2000 MW and 2500 MW). As mentioned in Section 5.6.1.0, the eight events are selected as being the most severe events – as well in power variation as in duration. Furthermore, these tests are carried out on different horizons of installed capacities, i.e. 4.4GW and 5.8GW.

The following steps have been performed in order to validate the newly received data and the model adaptations compared to the previous study as well as to analyse the impact, independently of the installed capacity scenarios and market performance assumptions:

a. Validation of the impact of modelling improvements and establishing consistency with previous validation study (impact of new data)

- Update of wind generation profiles
- Update of timings for the scheduled activation aligned with foreseen FRR product design
- Scheduled and direct activation considered simultaneously.

The updates to the model concerning the aFRR controller (Picasso design) and mFRR activation logic (Mari design) allow a better capture the flexibility behavior. These updates are found to have a marginal positive impact on the violation durations following the improved flexibility response.

Simulations in the 4.4GW horizon are carried out at first, to compare the impact of the revised DTU data and the modelling updates against the previous 4.4GW in the MOG 2 system integration study of 2020. This comparison against the previous reference establishes an understanding of the new revisions and provides a new point of reference against which the further studies assessing the impact of 5.8GW offshore wind capacity and expected market performance can be compared.

b. Analysis of impact of increasing the installed offshore wind power capacity from 4.4GW in the previous study to 5.8GW, based on the newly available data

Having established a new point of reference in the first validation study, the objective in this validation study is to observe the impact of 5.8 GW offshore wind capacity. The simulations carried out under this part of the study assume the previously considered market performance. This is done so as to focus only on the impact of increased offshore capacity. As it could logically have been expected, it is concluded from the outcomes of this study that there is a negative impact of the new installations on the violation durations, as for a given flexibility and unevolved market performance it takes a longer duration for the ACE to return to normal state.

c. Analysis of the impact of expected market performance, in the view of the new market performance assumptions

Following the modelling updates, revised data and new offshore capability the idea here is to assess the overall impact on the system considering the improved market behavior. In general, this has a positive effect on the violations compared to the previous study particularly for the best case simulations for which the market performance is substantially increased compared to the previous study. The study focuses on the violations observed in sensitivity corresponding to different market behaviors and flexibility situations across storm and ramping events. The observations of this study can be used as a reference to justify the need and study the impact of the proposed mitigation measures.

	MOG2 2020 Study	4.4GW Old BRP assumptions	5.8GW Old BRP assumptions	5.8GW New BRP assumptions
DTU data version	Old data	**New data**	New data	New data
Offshore wind power capacity	4.4 GW	4.4 GW	**5.8 GW**	5.8 GW
Technology scenario	Tech – B	Tech – B	Tech – B	Tech – B
Storm shutdown scenario	25m/s	25m/s	25m/s	25m/s
Sensitivity on available flexibility	1250 – 2500 MW	1250 – 2500 MW	1250 – 2500 MW	1300 – 2500 MW
Activation type	Direct + Scheduled	Direct + Scheduled	Direct + Scheduled	Direct + Scheduled
Market performance indicator version	Old indicators Best / Worst case	Old indicators Best / Worst case	Old indicators Best / Worst case	**New indicators** Best / Worst case
Measured impact	MOG II 2020	Impact of new DTU data	Impact of volume	Impact of new assumptions

Figure 113 : Overview of validation studies carried out for different sensitivities and scenarios

5.6.4. Results

This section presents an overview of the simulation results, obtained from the validation studies described in the previous section. The outcomes from the validation studies 'a' and 'b' as discussed in the previous section, were found to be in line with the expectation.

With the reference of validation studies "a" and "b", the focus of the section revolves around the observations in the validation study "c", performed to assess the impact of improved market performance.

As discussed in Section 5.6.1.2, the total (cumulative) violation durations for the eight events in storm (cut – in, cut – out), upward and downward ramping events are categorized into alert and emergency states and these are observed for two dimensions of sensitivities:

a) Market performance – represented by best or worst market performance scenarios;
b) The available flexibility – represented by the available FRR balancing energy scenarios.

5.6.4.1 Upward – storm

The observations for storm events, specifically the 'cut – in' or upward part of the storm, when the generation returns after a period of absence, are depicted in Figure 114. The figure shows the cumulative violations (representing excess energy in the system) observed for different FRR scenarios for both the best and worst market performance scenarios, and further classifies the violation duration based on the state of the system – alert and emergency.

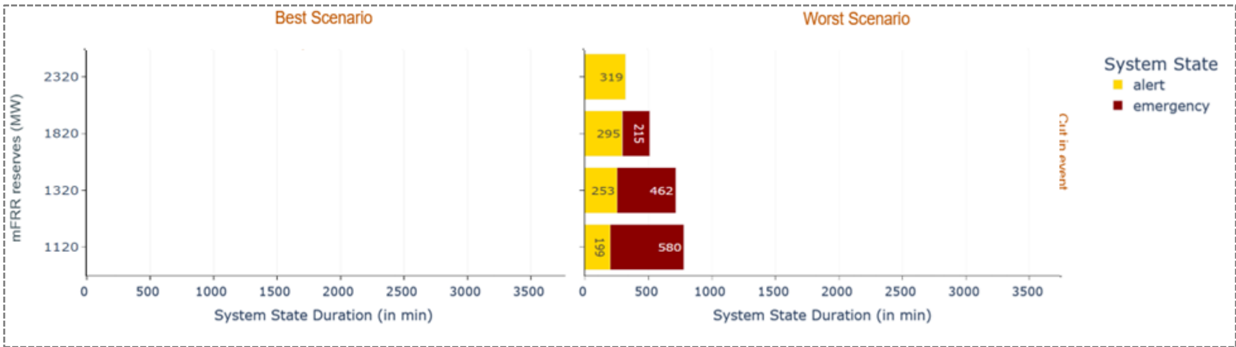


Figure 114 : Overview of cumulative violation durations in the case of storm cut-in events

Observations

- Violations with best market performance:
  - No violations are observed in any of the available FRR scenarios for all the eight simulated events. The market performance is sufficient to sustain the balancing needs even under the lowest available FRR reserves conditions.

- Violations with worst market performance:
  - Violations of alert and emergencies are observed for all available FRR scenarios (except for the highest reserve scenario where the violations remain limited to the alert state);
  - The observed violations in ACE are well correlated to the available FRR such that a maximum cumulative violation duration of 780 minutes (199 minutes of alert and 580 minutes of emergency) is observed in the lowest FRR scenario (1300 MW);
  - For a total simulation duration of 2913 minutes across eight events, the emergency state in the lowest FRR scenario lasts 580 minutes – giving a 20 % emergency duration;

- Violations remain limited to the alert state in the high FRR scenarios. For the highest FRR scenario of 2500 MW, the ACE still spends a total of 319 minutes in alert state, while the emergency state violations already occur 215 minutes in the FRR scenario of 2000 MW.

5.6.4.2 Downward – storm

The observations for storm events, specifically the 'cut – out' or downward part of the storm, when the generation is lost is depicted in Figure 115.

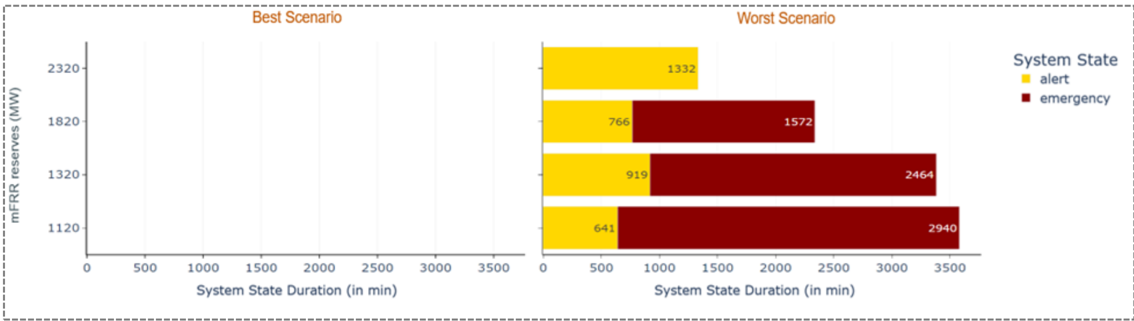


Figure 115 : Overview of cumulative violation durations in the case of storm cut-out events

Observations

- Violations with best market performance:
  - The market performance is sufficient to sustain the balancing needs, even in the lowest FRR scenarios. We nevertheless observe 5 minutes of Alert violations in total for all FRR levels (not observable on the graph due to the scale).

- Violations with worst market performance:
  - The worst market performance scenario observes alert and emergency state violations for lowest FRR scenarios studied (except for the highest FRR scenario where the violations remain limited to the alert state);
  - For the least FRR levels sensitivity, the total violation observed is 3581 minutes (641 minutes in alert state and 2940 minutes in emergency state);
  - For a total simulation duration of 5207 minutes across eight events, the emergency state in the lowest FRR cases lasts 2940 minutes – **giving a 56.4 % emergency duration;**
  - Violations remain limited to the alert state in the high FRR cases. 1332 minutes (out of a total 5207 minutes) of alert state are observed at the highest FRR, while the emergency state violations already occur 1572 minutes with an available FRR of 2000 MW.

5.6.4.3 Upward – ramps

The observations for upwards ramp events, for 25m/s direct cut-off technology with no ramping rate limitation, are as depicted in Figure 116.

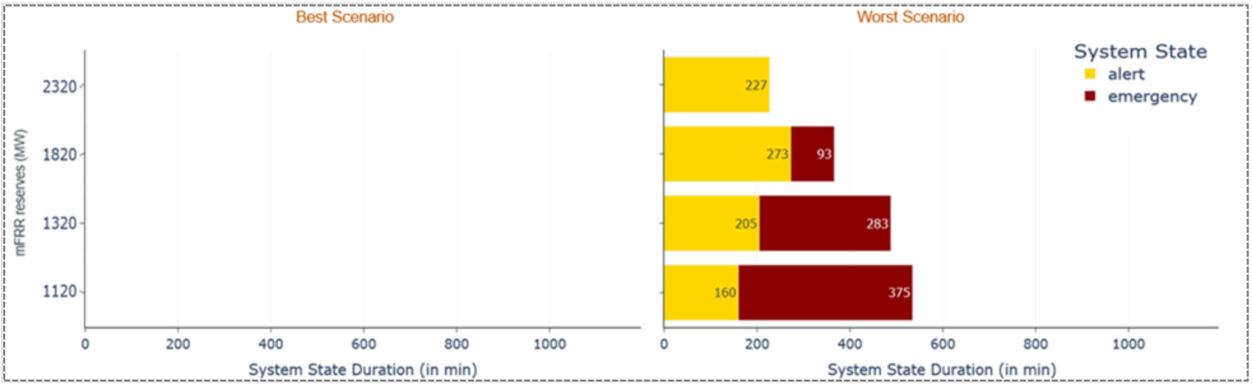


Figure 116 : Overview of cumulative violation durations in the case of upward ramping events

Observations:

- Violations with best market performance
  - The best market performance scenario is capable of sustaining the balancing needs even in the low scenarios;
  - It is important to note that the upward ramping events are simulated without any mitigation measures (ramping rate limitation) applied, and the fact that best market performance manages to avoid any violation in ACE.

- Violations with worst market performance
  - The scenario with worst market performance scenario observes violation durations in ACE in both alert and emergency states;
  - The violations observed are well correlated to the available FRR, with a maximum violation of 535 minutes (160 minutes of alert and 375 minutes of emergency) corresponding to the lowest FRR scenario (1300 MW);
  - For a total simulation duration of 2194 minutes across eight events, the emergency state in the lowest FRR scenario lasts 375 minutes – giving a **17 % emergency duration;**
  - For a worst market performance, situations with high FRR observe violations as well. An alert state for 227 minutes is observed for the highest sensitivity and while the next highest sensitivity observes an alert (273 minutes) state and an emergency state (93 minutes);
  - These results confirm the need for mitigation measures to manage excess energy, such as ramping rate limitation and cut-in coordination.

5.6.4.4 Downward – ramps

The observations for downwards ramp events, are as depicted in Figure 117.

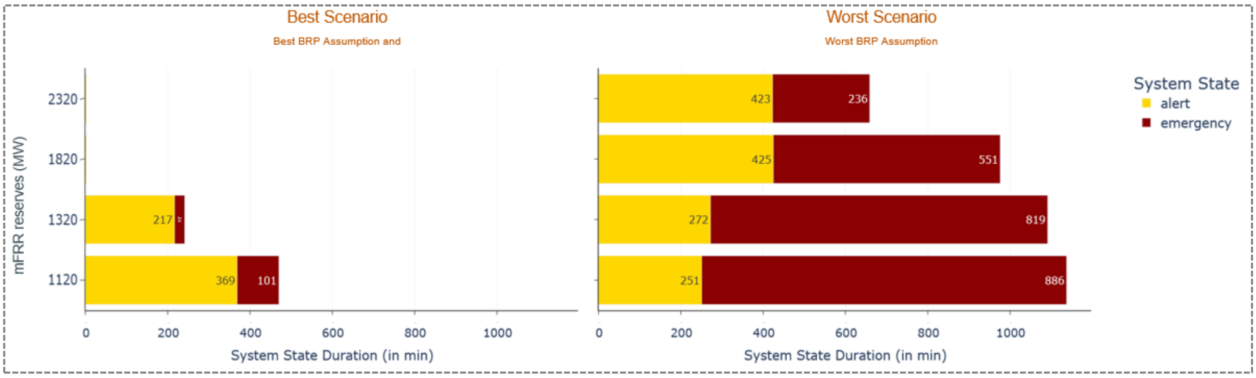


Figure 117 : Overview of cumulative violation durations in the case of downward ramping events

Observations:

- Violations with best market performance
    - The downward ramping events observe violations (in both alert and emergency states) for lower available reserve scenarios (case 1 and case 2) For a total simulation duration of 2548 minutes corresponding to the simulation of eight events, a total violation of 470 minutes (369 minutes of alert and 101 minutes of emergency) is observed – giving a 4% emergency duration.
    - Observing emergency in the best market performance further emphasize the need for mitigation measures, even under best case market performance.

- Violations with worst market performance
    - The downward ramping events observe a large amount of violations in all the simulated FRR situations;
    - A maximum violation of 1137 minutes (251 minutes of alert and 886 minutes of emergency) corresponding to the least FRR cases;
    - For a total simulation duration of 2548 minutes across eight events, the emergency state in the lowest flexibility lasts 886 minutes – **giving a 34.6 % emergency duration;**
    - Even in the highest FRR cases, violations are found to last.

The simulation also conveys that even with the highest flexibility the downward ramping events under 25m/s direct cut-off technology will experience emergency state violations in ACE (236 minutes). These observations in general shed light on the need for new mitigation measures to manage unexpected shortages. This issue was not identified in the previous study (2020), as upward and downward ramps were treated as a single event.

5.6.5. Conclusions

In order to evaluate the possible impact of the newly projected installed capacity of 5.8 GW on real time system operations, a set of eight events has been simulated for each scenario and sensitivity : (1) corresponding to the type of event, i.e. storm and ramping events, (2) the specific part of the event, i.e. upward (including storm cut-in events) and downward (including storm cut-out events), and (3) market conditions, i.e. with best and worst market performance and available balancing energy bids situations.

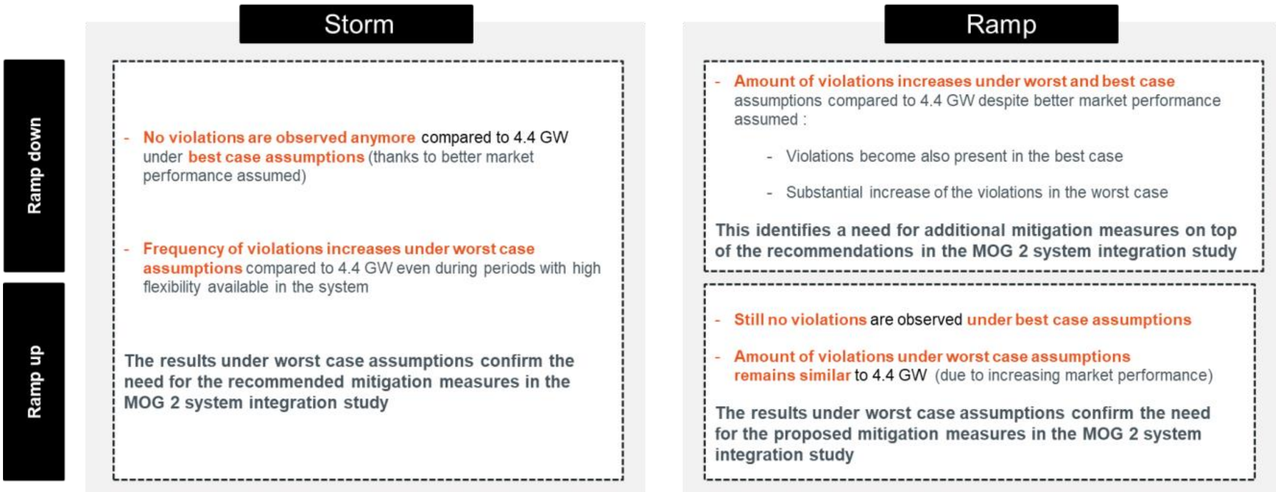


Figure 118: overview of conclusions for storm and ramp events

The analysis identified that when increasing the installed offshore wind power capacity to 5.8 GW, the violations differ from the MOG 2 system integration study in an expected manner: the new market performance assumptions, generally better than in the previous study, are observed to counter the increased offshore wind power capacity compared to the previous study (4.4 GW).

It is fair to say that neither the most pessimistic (worst case BRP reaction combined with lower FRR available flexibility) nor the most optimistic (best case BRP reaction combined with higher FRR available flexibility) cases are the most likely scenarios: the reality will likely be somewhere in between the different possible combinations depending on the BRP reaction, intraday and balancing market liquidity and speed of market reaction. Nevertheless, the worst case scenario remains a very relevant scenario for Elia as a safety net is required to balance the system if market performance would evolve to such scenarios.

The most important insights of our simulations show that:

1) For the storm cut-in and cut-out events,
- under the best market performance assumptions, no violations are observed which is similar to the MOG 2 system integration study. This can be attributed to the improved market performance compensating the impact of the increased offshore capacity;
- Increasing violations are observed under the worst-case market assumptions even under the assumption of higher market performance The duration of violations has increased, even in high available FRR scenarios due to the increased installed offshore wind capacity.

2) For upward ramping events:
- no violations are observed under the best market performance assumptions, similar to the MOG 2 system integration study. This can be attributed to the improved market performance compensating the increased offshore capacity;
- the number of violations under the worst market performance assumptions remain similar to the previous study as well. The effect of increasing the offshore wind power capacity is offset by the improvements in market performance.

3) For downward ramping events:
- It is important to note that the upward and downward ramping events (at wind speeds not related to storm events) are now investigated explicitly with different market performance for the upward and downward directions;
- under the best market performance assumptions, violations appear despite the improved market performance. This unsatisfactory performance in the best market performance scenario can be attributed to the fact that market performance assumptions remain similar as in the previous study, which combined with increased installed offshore wind capacity;
- under the worst market performance assumptions, the violations observed are substantially increased compared to previous study.

In general, the results under worst market performance assumptions confirm the need for mitigation measures presented in the MOG 2 system integration study. Based on the analysis of the results and their sensitivities, it is found that the negative impact of the storm and ramping events can be avoided by a combination of:

- Increasing the balancing market performance or availability of FRR (in Belgium or abroad) and/or
- Increasing the reaction speed for the activation of available FRR (by BRPs and/or Elia) and/or
- Reducing the impact of wind power deviations at the source by implementing the mitigation measures defined in the next section.

5.7. Mitigation measures for storm and ramping events

In its MOG 2 system integration study published in 2020, Elia already recommended three mitigation measures to manage the impact of storm and ramping events on system operations (Figure 119):

- enforce **High Wind Speed capabilities** on new offshore wind farms as a solution to limit the impact of storms to the extent possible;
- impose **Ramp rate limitations** on new offshore wind farms to manage fast and unexpected upward ramps during large excess system imbalances.
- extend the existing storm procedure with a measure for **Preventive curtailment** for new offshore wind farms in case of inadequate market response and expected flexibility shortages.

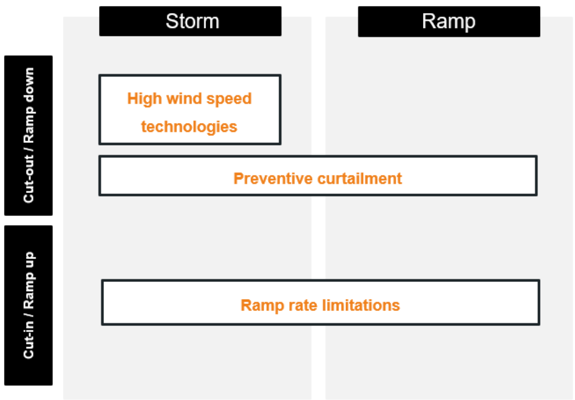


Figure 119: Overview of recommended mitigations measures for storm and ramping events

While these recommendations were drafted in a context of installing an additional 2.1 GW offshore wind power in the system, this study updates the analyses in view of the renewed offshore ambition to increase offshore wind power capacity with 3.5 GW towards 2030. This study needs to ensure that the system will be able to cope with 5.8 GW offshore wind power, while taking into account the impact of new evolutions concerning offshore grid topology (with hybrid interconnectors in a meshed HVDC network) and the potential connection of the additional wind power in an Offshore Bidding Zone (for which the impact is discussed in Section 5.8).

The proposed mitigation measures are based on four main principles. Firstly, all mitigations measures are designed to allow Elia to avoid system violations by design at any time. System simulations presented in Section 5.6 demonstrates the need for the mitigation measures to avoid alert and emergency state situations under worst case market conditions. In many situations with better market performances, the mitigation measures will not be triggered. But as the evolution of the market performances are uncertain, having the technical capabilities to effectively implement these mitigation measures is required and need to be ensured via the connection requirements that will be communicated during the tender in 2024. The mitigation measures are hence to be seen as a safety net that can be triggered in case of bad market performance.

Secondly, the recommended mitigation measures are designed to give market players all opportunities to self-manage the expected impact of storm and ramping events in the intraday, and even up to the balancing timeframe. By means of this market-first principle, the activation of the mitigation measures can be avoided under good market performance and no operational costs associated to the activation of the measure will be incurred under such situation.

Thirdly, the recommended mitigation measures are designed to be proportionate, in view of alternative solutions based on procuring additional reserve capacity, while ensuring a fair allocation of the costs to those parties responsible for these costs. This allocation of these costs needs to ensure appropriate incentives for involved market parties to avoid the activation of the mitigation measures under the second principle.

Fourthly, Elia aims to provide as much visibility and transparency towards the offshore wind power tender by presenting the design principles of the mitigation measures to market parties. Nevertheless, the recommended mechanisms will be subject to regulatory approval process, which is foreseen in the years ahead of the commissioning of the wind farms. System evolutions and discussions between the regulator, Elia and market parties, may therefore result in adjustments from the design proposed in this document.

5.7.1. High Wind Speed capabilities

5.7.1.1 Measure

This mitigation measure intends to enforce technical minimum requirements on new wind turbines of wind farms to maintain generation during high wind speeds. This allows to smooth the shutdown profile during a storm event and therefore reduce the frequency and impact of shortage of power following storm shut down wind speeds. The capability will be enforced through the connection requirements on new offshore wind turbines (Section 5.9). The measures require new offshore wind turbines to maintain generation until wind speeds of at least 31 m/sec and this after a gradual ramp down of the power output before full disconnection. The measure is based on the technical characteristics of HWS Deep power curves presented in Section 5.3.3.

These Deep HWS curves are based on storm shut down technologies as they are already installed in the latest of the commissioned offshore wind power plants in Belgium. Based on discussions with turbine manufacturers and inputs received from the Technical University of Denmark, these technologies are expected to be a standard feature for offshore wind turbines. Furthermore, no fundamental remarks were received from stakeholders when discussing the assumptions in April 2022 within the Task Force.

The technical requirement will require a power curve behavior as presented in Figure 120 which has to be respected at turbine level:

1) to avoid a sudden cut-off before 31m/sec (for an averaging time of 10 minutes) ;
2) a sudden cut-off with an instantaneous reduction of the wind power injection from full capacity to 0 MW will not be accepted and a minimum slope of power decrease will be requested with :
    a. gradual power decrease starting at an average wind speed at least 5m/sec below the sudden cut-out average wind speed (2a);
    b. gradual decrease of power must be guaranteed until a Nominal Power of at least 0.5 before sudden cut-out occurs (2b).

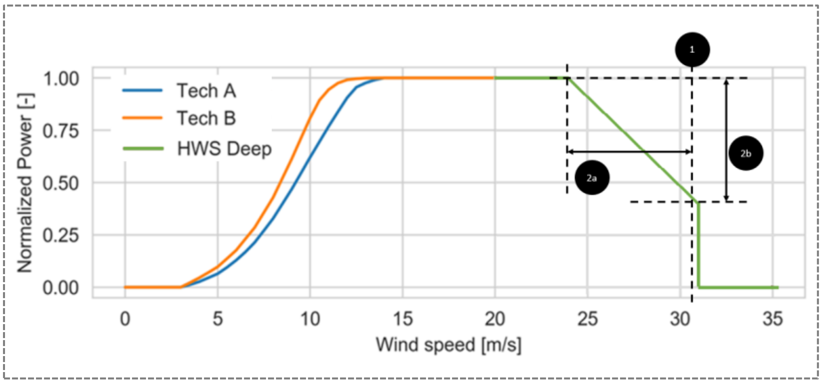


Figure 120: Illustration of the minimum requirements to be respected at turbine level for HWS mitigation measure[34]

If it would be explicitly requested by offshore wind power developers, an alternative can be based on the ability of wind farms to demonstrate that the solution chosen is at least equivalent at the connection point based on:

- extreme events (wind speed profiles) that need to be simulated to provide equivalent Power Output;
- resulting ramp rates difference (power output) shall not be worse than an equivalent behavior of the requested profile by Elia.

[34] *The Normalized Power from Figure 42 does not take include a possible "Boost function". In other words, a turbine is considered to deliver a normalized power of 1.00 without boost.*

5.7.1.2 Justification

Impact on wind power variations

The analyses of DTU (cf. Section 8.3. in the DTU technical report) shows how the Deep HWS capabilities can have a substantial effect on large downward ramping events during storm events compared to a direct cut-off as from 25 m/sec. The analyses of the frequency of large ramping events during high wind speeds days (maximum daily fleet-level wind speed above 20 m/s) in Table 31, Table 32 and Table 33 of the DTU technical report show that:

- The maximum downward ramp in 5 minutes is reduced from 1.5 – 2.0 GW to 0.5 GW while events happening more than once per year is reduced from 0.5 GW to 0.3 GW.

- The maximum downward ramp in 15 minutes is reduced from 3.0 - 3.5 GW to 1.5 GW while events happening more than once per year is reduced from 2.0 GW to 0.5 GW

- The maximum downward ramp in 60 minutes is reduced from the full 5.8 GW to 3.5 GW while events happening more than one event per year is reduced from 3.5 GW to 2.0 GW.

In contrast to the downward ramps, there are no positive effects associated to the upward ramp, which are found to face a slight increase of largest ramps during the re-activation (cut-in) phase after the storm. This is largely outweighed by the benefits of the capability as it is far more difficult to manage downward ramping compared to upward ramping events which can always be managed via downward activations and ramping rate limitations.

Impact on system violations

The positive effects of the Deep HWS capabilities are demonstrated by means of Elia's system simulations. Figure 121 compares the amount of alert and emergency state system violations in minutes over 8 storms events for best and worst case market conditions, and different levels of available balancing energy bids in the system. It is to be noted that there are almost no violations[35] observed under best case market conditions, regardless of the chosen turbine technology.

- The **HWS Moderate technology** (with a cut-off wind speed of 28 m/sec) increases the total amount of minutes in alert or emergency state compared with the HWS Deep technology with respectively 30%, on average (average 23% for the emergency state and 36% for the alert state).

[35] *Limited to 5 minutes for scenario with lowest available flexibility in the system (not visible in Figure 121)*

- The **25m/s Direct cut-off** increases the total amount of minutes in alert or emergency state compared with the HWS Deep technology and HWS Moderate technology with an average of respectively 52% (average 31% for the emergency state and 68% for the alert state) and 17% (average 6% for the emergency state and 25% for the alert state).

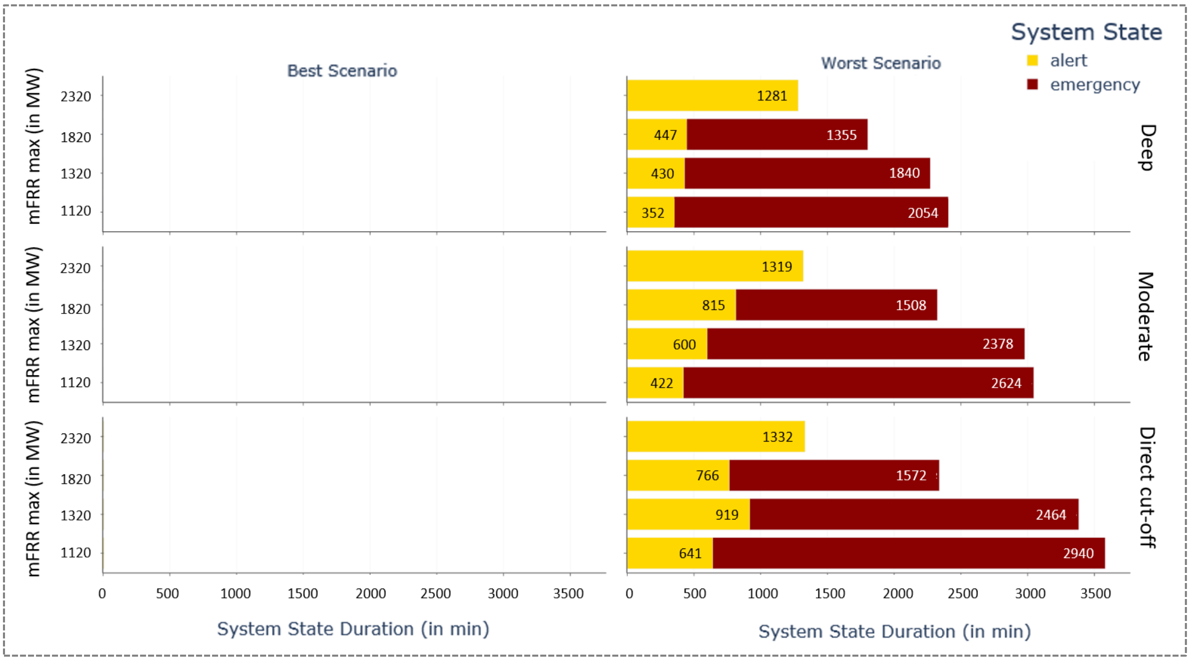


Figure 121 : Overview and comparison of simulation results for storm events for 25m/s direct cut-off ("DC"), HWS Deep ("Deep") and HWS Moderate ("Moderate") technology

When expressing the results in terms of number of violations it is shown that for the analyzed storm events, the number of alert and emergency sate violations are decreased when comparing the HWS Deep technology with the 25m/s direct cut-off or HWS moderate technology (Figure 122, left). Note that the four occurrences with the 25 m/sec direct cut-off for the alert state in relate to only 5 minute of violations.

Violation Count – Best case BRP reaction			
Violation Class	25m/s Direct cut-off	HWS Moderate	HWS Deep
Alert	4	0	0
Emergency	0	0	0

Violation Count – Worst case BRP reaction			
Violation Class	25m/s Direct cut-off	HWS Moderate	HWS Deep
Alert	32	32	25
Emergency	21	21	18

Figure 122 : Comparison of reported violation between "25m/s Direct cut-off", "Moderate" and "Deep" technology

The system simulations demonstrate that the HWS Deep technology is helpful in reducing emergency situations, particularly during:

- Worst case market behavior e.g. during unforecasted storm events
- Minimum availability of non-contracted mFRR balancing energy

Additional analyses also show that the biggest benefits compared to the direct cut-off are observed during the beginning of the storm-cut out.

However, the results also show that the obtained behavior is not sufficient to manage system violations during worst case market conditions. The HWS Deep technology measure will needs to be complemented with an additional mitigation measure as risk of emergency situations persist (the preventive curtailment presented in Section 5.7.3 Preventive curtailment).

5.7.1.3 Financial impact

While the presented Deep HWS capabilities may imply an investment cost for wind power developers, the requirements are reasonable in view of the benefits in terms of system operation:

- the market has already implemented HWS Deep technologies in the existing farms and the technology is expected to become a customary feature for turbine manufacturers;
- no objections were received by wind power sector (including technology providers participating in the TF PEZ) on the future technical capability;
- the use of HWS technologies is already incentivized through Elia's Grid Connection compliance requirements as per the actual "Compliance Simulation Procedure Type D PPM" : "*The PPM owner shall propose mitigation measures against high wind speed conditions (> 25 m/sec) that could result in large wind turbines infeed loss (for example wind turbines with 30 m/sec cut-off setting or different cut-off settings above 25 m/sec). The mitigation measures can be tested against a wind speed profile to be defined in agreement with Elia".*

In terms of operational costs, high wind speed capabilities allow to increase the generation of wind turbines during storm conditions by means of a higher cut-out wind speed and a lower cut-in wind speed. This is expected to reduce or even avoid the lost generation during a storm event and result in a positive impact on the revenues of the wind farms during operations.

5.7.2. Ramp rate limitations

5.7.2.1 Measure

This mitigation measure intends to limit the upward ramp rate of new offshore wind farms during elevated positive imbalances in the Elia LFC block. It aims to mitigate the frequency and impact of excess power following increasing wind speed conditions or re-activations (cut-in) after a storm by means of a simple, automatic and transparent procedure compared to the manual cut-in coordination of existing farms. The measure will be implemented via control requirements specified in the connection requirements while the operational procedure will be implemented via the regulatory framework (Section 5.9).

With this measure, the LFC block imbalance is continuously monitored by Elia. As shown in Figure 123, when the real-time LFC block imbalance would exceed a certain value (referred to as the RRL threshold), an activation signal is sent to the wind park which will need to implement the upward ramp rate limitation (RRL) within one minute after the signal was sent by Elia. Every time the real-time LFC block imbalance falls below the RRL threshold, the wind farms will be free again to ramp up without limits.

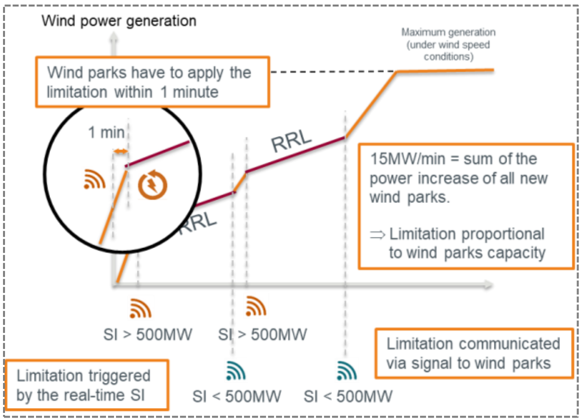


Figure 123 : Illustration of a wind power (fleet, park or turbine) cut-in after full cut-out

This trigger will be imposed on individual farms pro-rata to the installed capacity compared to the newly installed offshore capacity. In view of the foreseen 3.5 GW, this means that a park of 350 MW would face a limitation of 1.5 MW/min.

Note that this measure will be used for upward ramping events during storm conditions, during re-activation (cut-in) of the turbines after a storm, as well as during normal wind speeds (with fast wind speed variations on the exponential part of the wind power curve). In practice, Elia will transparently and automatically approve the cut-in of wind power (via intraday program change requests, IDPCRs) but subject to the imposed ramp rate limitation. Existing farms, subject to the current cut-in coordination, will be able to choose to remain subject to the current mechanism (and its foreseen evolutions), or the ramp rate limitation.

Existing cut-in coordination

Today, a requirement on cut-in coordination for existing offshore wind farms is already implemented in the Terms and Conditions Scheduling Agent and T&C Outage Planning Agent and is in line with Article 131 of the Code of Conduct.

Under this mechanism, when a storm event has ended, the Scheduling Agent Offshore Power Park Module requests the approval to cut-in by sending an IDPCR. Elia manually approves the IDPCR and coordinates the cut-in phase for each wind park individually.

Currently it still remains feasible for Elia to apply this on a case-by-case basis and this process rarely resulted in limitations of the wind farms. Nevertheless, this process needs to be automatized towards the commissioning of new wind farms following the increased complexity of managing additional wind farms.

In addition, market parties also request clear parameters and guarantees, particularly:

- Clear and transparent **framework** around cut-in coordination;
- No undue **delay** and a **maximum duration** of the cut-in;
- **Non-discriminatory** process between wind farms;
- Existing farms shouldn't be impacted by **new wind farms rules;**
- Take into account the **available technical functionalities.**

While the recommended ramp rate limitation is in line with these principles, not all existing farms are capable to react based on real-time signals. For the latter, the alternative solution proposed by Elia as "Automatic Cut-in Coordination" is to automatically approve the IDPCRs of existing farms while imposing a linear ramping profile (or equivalent) in a pre-defined period of around 1 hour after request to come back via the Scheduling Agent. Alternatively, for existing offshore wind farms **able to react on real-time signals**, the **Ramping Rate limitation** proposed to new farms **can be applied** instead of the automatic cut-in coordination.

Currently, the best setting of RRL and the RRL threshold is found to be respectively 15 MW/min and a system imbalance of 500 MW. As further discussed in Section 5.7.2.2, these parameters allow to solve most of the upward ramping violations, while limiting the impact on the capacity factor and giving an opportunity to the market to react to high imbalance prices before imposing a restriction. These parameters are foreseen to be specified in the LFC block operational agreements after consultation, and regulatory approval.

The ramping rate limitation would be imposed in line with SOGL Article 137(4)(a):

> *"All TSOs of an LFC block shall have the right to determine in the LFC block operational agreement the following measures to support the fulfilment of the FRCE target [36]parameter of the LFC block and to alleviate deterministic frequency deviations, taking into account the technological restrictions of power generating modules and demand units:*
>
> *(a) obligations on ramping periods and/or maximum ramping rates for power generating modules and/or demand units; …"*

Note that the ramping limitation is also foreseen in the European Network Code establishing Requirements for Grid connection of Generators (RfG NC). The provision is covered in Article 15(6)(e) and Article 28 covering General system management requirements applicable to AC-connected offshore power park modules. According to RfG, ramping limitation provisions can be asserted by a relevant System Operator in coordination with the relevant TSO to fix maximum limits on rates of change of active power output. The limits would take into consideration the nature of the prime energy mover (e.g., ramping down constraints are not possible in case of wind production for example). This is implemented at national level as per the provisions of the Article 114 of the Belgian Federal Grid Code.

5.7.2.2 Justification

An important assumption when determining the design of the measure are the assumptions on:

- RRL threshold: the LFC block imbalance level which trigger the ramp rate limitation sent by Elia;
- RRL: the value of the limitation expressed in MW / minute and to be understood as the sum of the allowed power increase of all new wind farms.

When dimensioning these parameters, a trade-off is searched between solving the violations identified and limiting the impact on the production of the wind farms. Elia's ambition is to eliminate all violations. However, as ramping rate limitations are only applied on new farms, the ramping rate limitation that would have to be imposed on these new farms to be able to solve all simulated violations solely with this mitigation measure is not proportionate to the risk caused by these new farms.

Simulations in the MOG 2 system integration study calibrated these parameters at a System Imbalance of 500 MW (RRL threshold) and 15 MW / min (RRL):

[36] *FRCE is equal to the ACE of an LFC Area*

- Simulations of the RRL threshold between 300 MW and 500 MW have shown that no significant improvement on the system violations is incurred with a threshold of 300 MW. For this reason, it has been chosen to keep the target value of 500 MW. Even while some violations remain, it is difficult to justify a threshold lower than 300 MW to maintain a reasonably low activation frequency of the measure;
- Simulations on the RRL between 15 MW / min and 25 MW /min have shown that a limit of 15 MW / min still maintains some system violations, hence a higher RRL was not considered.

Figure 124 represents the impact of the ramping rate limitation of 15MW/min with an activation threshold of 500 MW, expressed in cumulative duration of violations. The figure only shows the result for the worst case market performance scenario as the best case market performance does not show any violations, even without the mitigation measure. It is shown in this figure how all violations can be mitigated during periods with available reserves while emergency state violations can almost be entirely mitigated under periods with low available balancing energy bids.

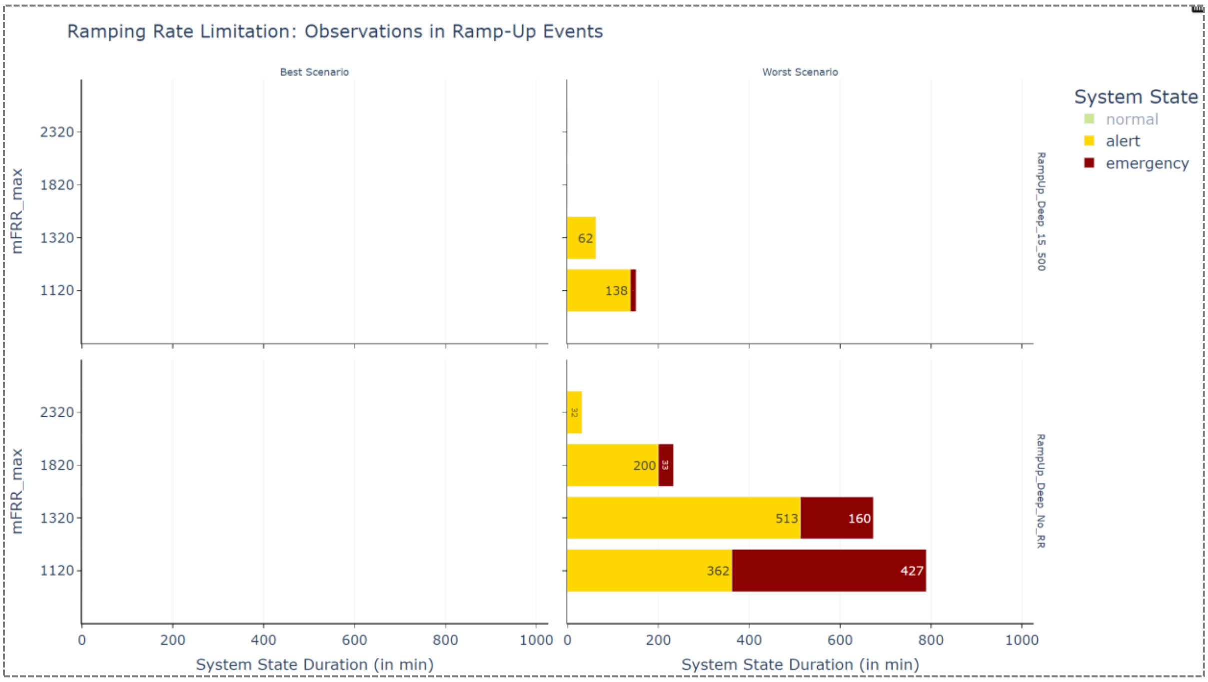


Figure 124 : Overview of duration of violations over eight simulations per scenario (market performance and available mFRR) for upward ramping events with (up) and without (down) a ramping rate limitation of 15MW/min triggered by a SI of 500MW

Figure 124 and Figure 125 demonstrate the effect of the recommended ramp rate limitation (with RRL at 15 MW/min and the RRL Threshold at 500 MW) in terms of duration and frequency of system violations.. It is to be noted that in these simulation, the ramping rate limitation was only implemented for the additional 3.5GW offshore wind capacity. No cut-in coordination was considered for the 2.3GW of existing capacity. Results show that the Ramping rate limitation measure does not just shortens the time spent in alert or emergency state but also reduces the number of events for which a violation is noticed.

Violation Count – BRP Optimistic scenario		
Violation Class	Without ramping rate limitation	With ramping rate limitation
Alert	0	0
Emergency	0	0

Violation Count – BRP Pessimistic scenario		
Violation Class	Without ramping rate limitation	With ramping rate limitation
Alert	20	3
Emergency	11	1

Figure 125 : Comparison of reported violation observed without Ramping Rate Limitation and with Ramping Rate limitation of 15MW/min triggered by a SI of 500 MW

Ramping rate limitations should only be applied when it is strictly needed to guarantee system security. When the market properly forecast and compensate the occurrence of an increase in offshore wind production, the ramping rate limitation should not be triggered. But once triggered, it is valid for all new offshore wind farms. Therefore, both the system imbalance and the FRCE were initially investigated as possible triggers to activate the restriction. The advantage of selecting the FRCE is that it would take into account the reserves activated by Elia. This can be relevant when the upward ramping event is occurring when upward FRR has been activated to compensate for a negative SI. However:

- The time necessary to deactivate the upward FRR is expected to allow the FRCE to remain under control without ramping rate limitation on the wind farms;
- Triggering limitations based on the system imbalance has the advantage of constraining BRPs to improve their instantaneous balancing position or to help the system. This would not necessarily be the case when using the FRCE instead;
- Triggering limitations based on the FRCE might lead to wrong price signal given to the market.

5.7.2.3 Financial Impact

The activation of the ramp rate limitations in the balancing timeframe mitigates the injection of excess energy of the wind farms. While this does neither impact the day-ahead nor the intraday market revenues, this will reduce potential balancing revenues when the imbalance price would be positive. However, as this measure is only expected during large positive LFC block imbalances (representing large excess power in the system), imbalance prices are typically low during such periods, and can even be zero or negative. In such case, the impact on these lost revenues are expected to be limited, and may even result in a financial gain during negative price period.

When the wind farms are subject to a capability-based contract-for-difference, there is no financial impact on the subsidy revenues as the capability-based nature determines the level of the subsidy on the potential injection and not on the physical injection. Under such subsidy scheme the financial impact of the activation should remain limited to the balancing cost as specified in the previous paragraph. Also under a

Power Purchasing Agreement, the financial impact should remain limited to the balancing costs as there is no subsidy revenue which can be impacted by the activation. The balancing costs will be allocated to the wind park or the purchasing party depending on the contractual agreement between them.

Note that in a well-functioning balancing market, the imbalance price gives a signal to market parties to sustain excess injection as long as the downward flexibility in the system can cope with these injections. Under such conditions, positive imbalance prices incentivize to maintain injections. On the other hand, during downward flexibility shortages, prices become zero to negative, incentivizing market parties to cease injections. Under normal conditions, such reaction from market parties will avoid large positive LFC block imbalances and avoid triggering the ramp rate limitations. Nevertheless, it remains possible that market players are not able to recover their position quickly enough to avoid activation e.g. following fast variations which could prevent the market parties to immediately recover its position. Nevertheless, the ramp rate limitation will be de-activated as soon as the market reacts and the LFC block imbalance return below the threshold.

Finally, the results in Section 5.4 demonstrate that large upward ramping events which are more susceptible to lead to high positive imbalances, do not happen at very high frequency.

5.7.3. Preventive curtailment

5.7.3.1 Measure

This mitigation measure is based on a preventive curtailment of the injections of new wind farms which will communicated during the intraday timeframe. This measure incentivises affected BRPs to source the energy to be curtailed on the intraday market to cover their day-ahead positions and avoid the expected imbalances caused by the storm or ramp events. The measure anticipates downward variations of wind power and therefore avoids imbalance shortages resulting in system violations. Note that the measure will only be applied when market players are not adequately covering the identified balancing risks and if Elia identifies insufficient reserve capacity in the system.

The trigger to preventively curtail wind farms will be based on the Elia's current storm procedure (Figure 126). This procedure is based on three steps:

- In a first step, the forecast of a storm by Elia (based on its weather-based forecast tools) will trigger the storm procedure. This will result in sending a storm alert which will be communicated to the market parties;

- In a second step, market parties will communicate to Elia the actions undertaken to manage the storm risk in their portfolio. Based on the interaction with Elia, the remaining shortage risk will be identified by Elia;
- In a third step, Elia will assess the remaining shortage risk in terms of reserve capacity in the system by means by means of available contracted and non-contracted balancing energy bids. If potential shortage risks are identified, Elia will fall back on the exhausted reserve procedure.

Figure 126 : Representation of the existing storm procedure

In the current fallback mechanism, Elia instructs the start of units with a slower start up time, typically of a few hours (currently conventional gas-fired power plants but a technology neutral framework will be put in place as from 2024 to allow participation of other technologies) to run a minimal power to deliver upward flexibility to the system to cover potential energy shortages during the storm. The trigger of this exceptional balancing measure (also referred to as the exhausted reserve procedure) is specified in the LFC block operational agreement while the activation procedures for selected units are specified in the Terms and Conditions BRP.

This existing fallback measure is recommended to be complemented with the mitigation measure to preventively curtail injections of new offshore wind farms in the Princess Elisabeth Zone. If the expected shortage risk cannot be managed by actions of the affected BRPs, or by Elia's reserve capacity, or by creating additional flexibility through the activation of additional slow start units, the additional shortage risk will be managed by Elia via preventive curtailment communicated to offshore BRPs the intraday timeframe. The curtailed volumes will be allocated to the affected BRPs pro rata to their contribution in the shortage risk. A security margin on the starting and ending time of curtailment will be considered to cover cases where storm or ramping events occur earlier or later than forecasted.

While the current exhausted reserve procedure is currently only put in place for storm events, the trigger is recommended to be extended for downward ramping events. The success of the measure for this type of events nevertheless depends on the feasibility of accurate forecast of such ramping events and uncertainty still exists if the measure can adequately cover ramping events. It is therefore not excluded that the limited predictability may require complementary solutions such as for instance the procurement of additional upward balancing capacity.

5.7.3.2 Justification

Elia's system simulations show that the measure is needed to deal with storm cut-out events and downward ramping events as shown in Section 5.6.4.2 and Section 5.6.4.4.

Section 5.6.4.2 shows that storm cut-out events create many violations. Part of those violations are managed via the High Wind Speed deep mitigation measure. However, as demonstrated in section 5.7.1, this mitigation measure does not suffice to resolve all violations and the preventive curtailment measure is needed to deal with such situations.

Moreover, in Section 5.6.4.4, it was shown that downward ramping events during wind speeds which are not related to storms also create a significant number of violations. No other measure is currently in place or foreseen to manage those violations. The extension of the preventive curtailment measure is thus needed to mitigate the effect of those downward ramping event provided that a reliable forecast of such events can be developed.

5.7.3.3 Financial impact

The activation of the measure results in a communication in the intraday timeframe in which the wind power injection will be announced to be curtailed in real time to anticipate unmanaged downward variations of wind power (following storm or other weather-related variations). The measure will only be triggered when BRPs are not adequately covering the identified balancing risks.

The mechanism, when activated, will create a shortage in the portfolio of the BRPs subject to the measure and facing an uncovered imbalance risk in their portfolio. This will incentivize them to buy energy in the intraday market to avoid the shortage in their portfolio in real-time. As the mechanism is foreseen to be communicated during the intraday timeframe, there is no impact on the day-ahead market revenues. However, there is an impact in the intraday market cost as the involved market parties will need to buy additional energy. On the other hand, the activation avoids a shortage position in real-time and will avoid balancing costs.

In case of a perfect forecast and trigger, the cost will correspond with the spread between the intraday and imbalance prices. Note that this can even result in a revenue as it is possible that the imbalance price is higher than the intraday market price. In case of an imperfect forecast and trigger (false trigger), the cost will correspond entirely to the intraday market costs.

Similarly to the ramp rate limitation, there is no financial impact on the subsidy revenues in capability-based contract-for-difference. Under such subsidy scheme, the financial impact of the activation should remain limited to the balancing cost as specified in the previous paragraph. Also under a Power Purchasing Agreement, the financial impact will remain limited to the balancing costs as there is no subsidy revenue impacted by the activation. The balancing costs will be allocated to the wind park or the purchasing party depending on their contractual agreements.

Note that in a well-functioning balancing market, the intraday and imbalance price gives a signal to market parties to anticipate a storm or downward ramping event. Under such conditions, positive imbalance prices incentivize to avoid shortages to the extent possible. If after a storm trigger, it would result that market parties have taken sufficient measure to manage the imbalance risk, the preventive curtailment will not be triggered. If the mechanism is triggered, it will only affect the wind power plants with uncovered imbalance risks.

Finally, during situations with lots of flexibility by means of balancing energy bids in the system, the measure will not be activated.

It is also important to note that expected observations following storms remain relatively rare. Based on 2020-22 observations, it is limited to 4 storms a year of, lasting on average 13 hours, meaning an average impact of only 52 hours per year. As explained above**,** the market reaction is expected to further reduce the frequency of triggering preventive curtailment.

Large downward ramping events may happen more frequently (downward ramping of 2.0 GW may happen around 10 days per year) but happen with shorter duration (around two hours). Market reaction is expected to further reduce the frequency of triggering preventive curtailment. As mentioned above, the effectiveness of this measure to cover system violations depends on future predictability of ramping events and a failure to develop accurate forecast might result in a need for additional measures.

5.8. Impact of OBZ and hybrid interconnection configurations on balancing market design

Section 4 of this consultation document explains that an offshore bidding zone and a hybrid interconnection configuration is considered for part or even all new offshore wind farms connected to the Princess Elisabeth Zone. **This section investigates the potential implications of these evolutions for the balancing timeframe in general, and the impact on the mitigation measures for storm and ramping events in specific**. While the second objective needs to ensure robust technical requirements for new offshore wind parks, which are valid for any grid or market context, the first objective aims to provide stakeholders as much visibility as possible on the future market design in view of preparing their offers for the offshore wind power tender.

Firstly, it has to be stressed that this topic remains new in the electricity sector and lacks best practice examples while literature on the subject remains limited to high level discussions on operational implications of offshore bidding zones. Secondly, it has to be kept in mind that the legal framework has initially not been conceived for a context with such bidding zones, connecting mainly generation capacity and little to no offtake. Thirdly, there remains uncertainty on the final grid topology as well as the capacity of wind power which will be connected to the offshore bidding zone. It is therefore the ambition of this text to put forward a robust balancing market design, of which the principles remain valid for any possible scenario.

In order to conduct this analysis, several questions need to be answered: (1) how will reserves be activated in an offshore bidding zone, (2) how will the dimensioning of reserves be conducted, and (3) what will be the impact on the activation of the proposed mitigation measures. This has to taken into account that an offshore bidding zone is not a regular bidding zone in terms of balancing as it is characterized with high forecast risks due to the large concentration of variable generation while facing no flexibility other than the downward flexibility delivered by the wind power itself, at least when assuming no other demand, storage, or generation technologies in the offshore bidding zone.

5.8.1. Legal justification

Article 6(6) of the Regulation (EU) 2019/943 of 23 November 2017 establishing a guideline on electricity balancing (hereafter referred to as EB Regulation) stipulates that each imbalance price area shall be equal to a bidding zone, except in the case of a central dispatching model where an imbalance price area may constitute a part of a bidding zone.

- According to Article 2(65) of the Regulation (EU) 2019/943 of 5 June 2019 on the internal market for electricity (hereafter referred to as CEP Regulation) a ‘bidding zone’ means the largest geographical area within which market participants are able to exchange energy without capacity allocation.
- According to Article 2(13) of the EB Regulation an ‘imbalance price area’ is the area for the calculation of an imbalance price.
- According to Article 2(18) of the EB Regulation a ‘central dispatching model’ is a scheduling and dispatching model where the generation schedules and consumption schedules as well as dispatching of power generating facilities and demand facilities, in reference to dispatchable facilities, are determined by a Transmission System Operator (TSO) within the integrated scheduling process. In contrast, according to Article 2(17) of the EB Regulation, a ‘self-dispatching model’ is a scheduling and dispatching model where the generation schedules and consumption schedules as well as dispatching of power generating facilities and demand facilities are determined by the scheduling agents of those facilities.

As the Belgium system is a self-dispatching model, it is thus concluded that the implementation of an offshore bidding zone in Belgium legally requires a separate offshore imbalance price area. Note that the geographical scope of the imbalance price area can be considered equal to the imbalance area, defined by Article 2(11) of the EB Regulation as the area in which an imbalance is calculated.

According to Article 54(2) of the EB Regulation, in a self-dispatching model, the geographical scope of an imbalance area is also equal to the scheduling area specified in Article 3 of the Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation (hereafter referred to as SO Regulation). A scheduling area is specified as an area within which the TSOs' obligations regarding scheduling apply due to operational or organizational needs. Article 110(2) of the SO Regulation specifies that where a control area covers several bidding zones, the geographical scope of the scheduling area is equal to the bidding zone. A control area is also defined in CEP Regulation Article 2(67) as a coherent part of the interconnected system, operated by a single system operator and including connected physical loads and/or generation units if any.

Figure 127 shows a graphical overview of these definitions. It allows to conclude that the Elia control area, when containing the onshore and offshore bidding zone, will also need to contain a separate offshore imbalance area, imbalance price area and scheduling area. This is also in line with the spirit of the creation of bidding zones, where energy prices account for the transmission capacity between these zones and reduce the need for internal re-dispatching.

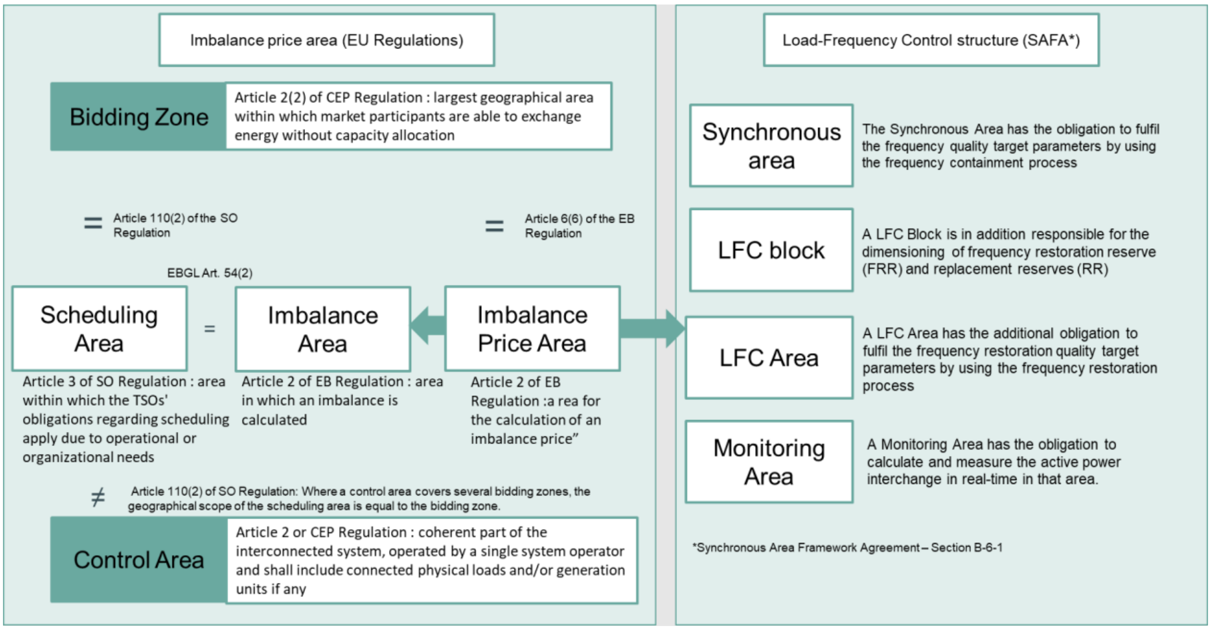


Figure 127 : Graphical overview on legal specifications on market and system structure

Unfortunately, the legal framework does not make an explicit link with the Frequency restoration process and the related Load Frequency Structure specified in the SO Regulation determining the activation of FRR reserve capacity. The activation of reserves is a responsibility of the LFC Area (or 'load-frequency control area') and is defined in SO Regulation Article 2(12) as a part of a synchronous area or an entire synchronous area, physically demarcated by points of measurement at interconnectors to other LFC areas, operated by one or more TSOs fulfilling the obligations of load-frequency control. The LFC structure in Europe is further described in the Synchronous Area Operational Agreement (B-6-1-1). Note that:

- 'Load-frequency control block' or '**LFC block'** defined in Article 2(18) refers to a part of a synchronous area or an entire synchronous area, physically demarcated by points of measurement at interconnectors to other LFC blocks, consisting of one or more LFC areas, operated by one or more TSOs fulfilling the obligations of load-frequency control;
- '**Synchronous area'** defined in Article 2 of Commission Regulation (EU) 2016/631 of 14 April 2016 establishing a network code on requirements for grid connection of generators refers to an area covered by synchronously interconnected TSOs, such as the synchronous areas of Continental Europe, Great Britain, Ireland-Northern Ireland and Nordic and the power systems of Lithuania, Latvia and Estonia, together referred to as 'Baltic' which are part of a wider synchronous area.

As approved in the latest version of the LFC block for the Synchronous Area Continental Europe, the Elia LFC Area currently equals the Elia LFC block being part of the Continental Europe Synchronous Zone.

As the LFC Area has the *obligation to fulfil the Frequency Restoration Control Error Target Parameters by using the Frequency Restoration Process (FRP),* **a separate imbalance area in the framework of an**

offshore bidding zone in Belgium needs to be established via a separate Frequency restoration process subject to an LFC Area. Indeed, it will be difficult to create efficient price signals if these do not follow separate activation signals (demand) and balancing energy offers (supply).

In practice, this means the Belgian offshore bidding zone will be characterized by separate offshore imbalance price area and offshore LFC Area, with separate activations of FRR reserve capacity through the EU balancing energy platforms Mari (for mFRR) and Picasso (for aFRR). Such approach is consistent with existing practices where, for instance in Germany, each of the LFC Areas has a separate activation process, with separate activation and offered balancing energy orders in the balancing energy platforms Mari and Picasso[37].

It can already be noted that the current Elia LFC block can be maintained, overarching the onshore and offshore LFC Areas. Also here, Germany can be seen as a practical example where the dimensioning of reserve capacity is conducted on LFC block level, overarching the four LFC Areas. Alternatively, creating separate LFC bocks which separates the onshore and offshore dimensioning is found to result in several legal constraints and methodological complexities while not creating any economic or operational value. This will be demonstrated in the Section 5.8.3 on reserve dimensioning.

5.8.2. Balancing market implications

The implication of operating a separate LFC Area is distinguished in this report as the real time operational timeframe, which is about the (milli-)seconds reactions and balancing market timeframe, where the market has the time to react to activation signals or to prices.

5.8.2.1 Real time operational timeframe

The HVDC nature contains features and challenges, independent from the market set-up, which are important to understand before discussing the balancing timeframe. Maintaining an instantaneous balance between the injection and offtake is of utmost importance on the HVDC converter as it directly impacts the DC voltage stability and the safe operation of assets. This is even more stringent than in an AC system due to the lack of inertia. The HVDC controller, being the interface between DC and AC grid, will be adjusting automatically to maintain the voltage stability in the HVDC system, and this by exchanging energy with the connected AC system.

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[37] *Elia plans to connect to Mari and Picasso as from 2024.*

In the target grid (Figure 128), this can be conducted by means of a joint operation of the different HVDC controllers:

- The Belgian master controller will balance the HVDC system by means of managing the injection and offtake through the convertor from the offshore HVDC system to the Continental Europe Synchronous area. As the Princess Elisabeth Island and its connection to shore is part of the Elia grid and thus operated by Elia, voltage deviations are to be managed in first instance through this master controller with Belgium;
- The convertors with UK and the Danish system (DK1, or an offshore bidding zone on the Danish side given the perspective of a hybrid set-up on the Danish end, may also contribute to balancing the HVDC system by means of managing injection and offtake with the UK or the Continental Europe Synchronous area via Denmark (DK1). Note that such behavior requires specific operational and or balancing agreements with these regions.

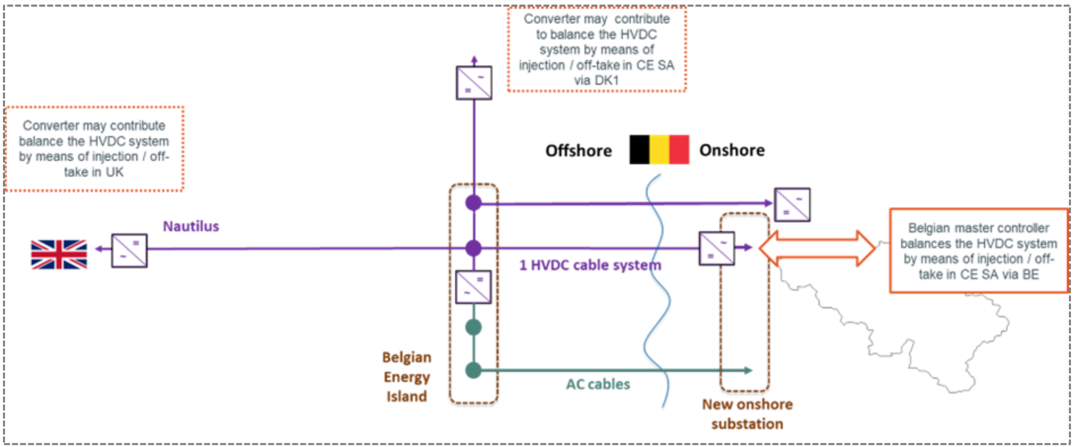

Figure 128 : Visual representation of multi-terminal DC control

Figure 129 illustrates the operation of a hybrid HVDC system in a split node topology (without connection between the offshore DC and AC system). Assume in first instance a shortage of generation where an unexpected reduction of the wind power infeed occurs (a). The HVDC system will react instantaneously to maintain DC voltage stability and balance within few milliseconds (b) by:

- reducing injection to Belgium when importing to Belgium from the island;
- increasing offtake from Belgium when exporting from Belgium to the island.

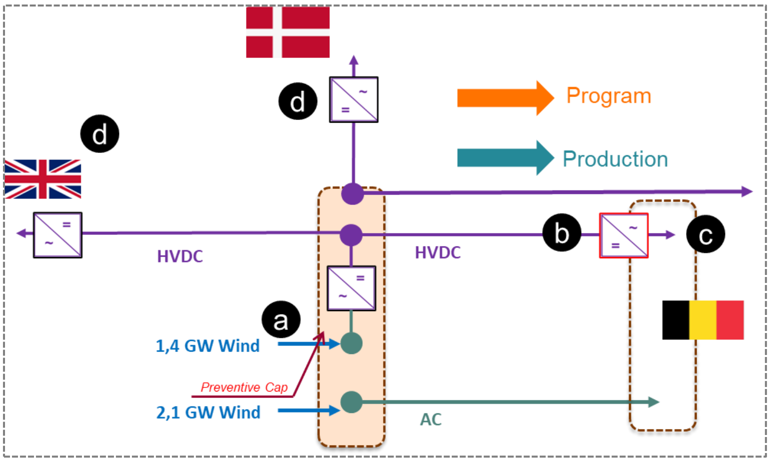

Figure 129 : Illustrative example of real-time operational management of a hybrid offshore HVDC system

This reaction will create a shortage of energy and hence a frequency deviation in continental Europe which will be compensated in the synchronous area via FCR (c). As mentioned above, it is however not excluded that the operations can be optimized by means of operational or balancing agreements with UK and Denmark (point d):

- increase off-take from (or reduce injection to) UK, if cheaper balancing energy and network capacity is available (to be compensated in in the UK synchronous area);
- increase off-take from (or reduce injection to) DK, if cheaper balancing energy and network capacity is available (to be compensated in the synchronous area of Continental Europe).

Note that a particular case can occur when assuming an excess generation due to an unexpected increase of the wind power infeed. Similarly, the HVDC system will react instantaneously to maintain DC voltage stability by:

- increasing injections to BE when exporting to BE from the island
- reducing offtake from BE when importing from BE to the island

This reaction will create an excess in the mainland (to be compensated in the synchronous area via fast FCR). However, during high import situations from the Princess Elisabeth Island to Belgium, it is possible that the capacity in the HVDC system is fully used, hence physically not allowing to further increase injections to the Belgian shore. In this case, the offshore wind power is subject to a ‘**preventive cap’** to avoid overload of the HVDC system caused by unscheduled excess of wind power generation.

Also here, operations can be optimized, and even limit the frequency and impact of triggering the preventive cap, by means of an operational or a balancing agreements with UK and/or Denmark:

- increase injections to (or reduce offtake from) UK, if cheaper balancing energy and network capacity are available (to be compensated in UK synchronous area);

- Increase injections to (or reduce off-take from) DK, if cheaper balancing energy and network capacity are available (to be compensated in Continental Europe).

The preventive cap is a specific measure needed for managing the hybrid use of an of HVDC system and will apply irrespective of the market setup. The congestions in the AC system remain relevant, however no specific measure is needed as they are managed through the general local congestion management framework.

Note that in a single node configuration the AC system offers a path parallel to the HVDC system to manage the imbalances. The single node configuration thus enables operations to be further optimized, hereby reducing the frequency and the impact of the preventive cap.

Implementation of the preventive cap

The preventive cap is implemented as a real-time injection limit enforced by Elia on the wind parks to safeguard operational security in the HVDC system. It is foreseen to be implemented as a physical real-time measure preventing excess injections of wind energy beyond the operational limits of the HVDC system. The injection limit will be determined based on the available capacity of the HVDC system.

Best estimate of the preventive cap

To enable the wind farms to have a foresight on what will be the possible injections in real time, a best forecast of the preventive cap will need to be available. It is defined as an expected operating margin. The approach is dependent on the market set-up. A high level overview of the approach is presented in Figure 130.

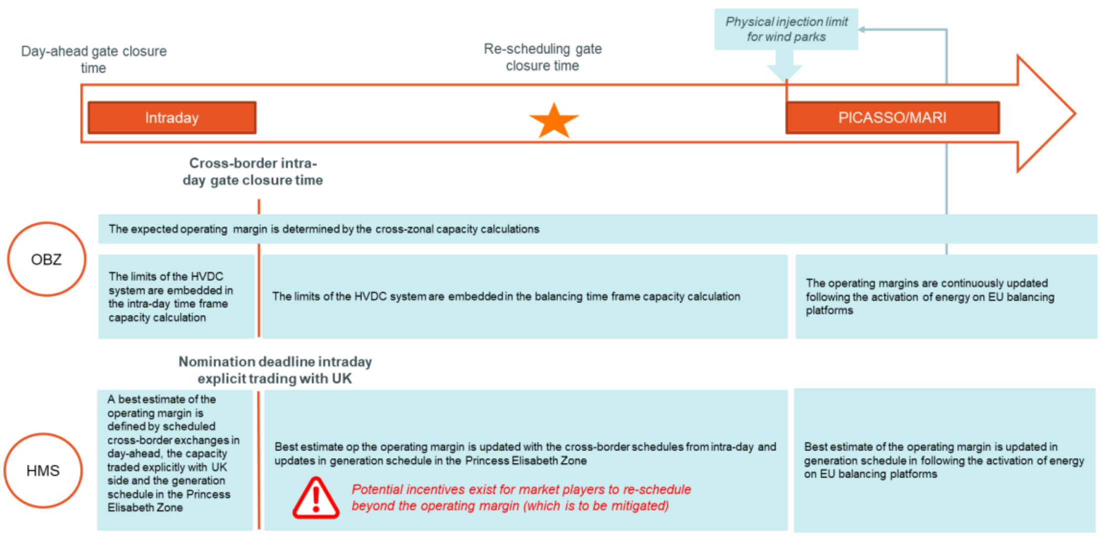

Figure 130: implementation of the preventive cap

Determining the best forecast of the preventive cap within an offshore bidding zone set-up

The reference market setup is the offshore bidding zone, implying that the bidding zone border between the offshore bidding zone and the Belgian bidding zone is subject to cross-zonal capacity calculation in the Core region.

During intraday, the intraday cross-zonal capacity calculation and the subsequent implicit allocation of the available capacity in single intraday coupling includes the limits of the HVDC system. After the closure of the cross-zonal intraday market and prior the opening of the balancing markets, the cross-zonal capacities are re-calculated through a balancing timeframe capacity calculation. The limit of the HVDC system is herein included.

No possibilities exist after the cross-border intraday market gate closure for market players to re-schedule their positions based on exchanges between the onshore and offshore bidding zone as even the exchanges between the Princess Elisabeth Island and the Belgian bidding zone are considered to be cross-border, and such exchanges are not possible anymore.

The best forecast of the preventive cap is thus fully included in generic capacity calculation processes and no specific communication or additional constraints are needed. There is no financial incentive to deviate from the schedule in case of excess power in the offshore bidding zone, as the imbalance price is expected to be zero in such circumstances. However, the implementation of the preventive cap will remain as a safety measure to avoid injections beyond the operating margin of the HVDC system.

Determining the best forecast of the preventive cap within a home market setup

Contrary to the reference market set-up with an offshore bidding zone, the technical limit of the HVDC system in a home market setup will not be covered by a calculation of cross-zonal capacities on the connection between the Princess Elisabeth Island and the Belgian onshore grid.

A best forecast of the preventive cap is thus to be calculated by Elia based on the technical limit of the HVDC system and its usage by the market.

From the day-ahead market closure until the nomination deadline for the intraday explicit trading with UK:

- On the UK side (interconnector perspective): explicit intraday trading will be in place. A capacity split between offshore wind and the interconnector with UK will be necessary for any remaining capacity on the connection between the Princess Elisabeth Island and the Belgian onshore grid. The most up-to-date assumptions (wind forecast) will determine which capacity will be made available for intraday trading between UK and Belgium.

- On Belgian side (offshore wind perspective): while the Princess Elisabeth Zone will be part of the Belgian bidding zone, the capacity to trade over the HVDC system needs to reflect the physical possibility of the system as it would have been the case if the preferred target model would have been implemented (with an offshore bidding zone and implicit trading). The calculation of the best estimate of the preventive cap will take into account the scheduled cross-border exchanges in day-ahead and intraday, the capacity traded explicitly with UK and the generation schedules in the Princess Elisabeth Zone to define what is left available on the HVDC link between the Princess Elisabeth Island and the Belgian onshore network.

To avoid any unfeasible commercial trades, meaning going beyond the technical capacity of the HVDC system, an update of the generation schedule in the Princess Elisabeth Zone beyond the best estimate of the operating margin will not be allowed. In contrast to an offshore bidding zone, market actors in a home market context might have the possibility and the potential incentive to deviate from their schedule in the balancing timeframe. Indeed, it is possible that imbalance prices remain positive following shortage situations onshore. When such situation would lead to an overload of the HVDC system, the preventive cap would act. This situation can be prevented by keeping communicating the operational margin also closer to real-time, so that the market actors know whether there is a possibility to react to the imbalance price.

5.8.2.2 Balancing timeframe

In the balancing market timeframe, the above-mentioned situations with excess or shortage wind power will result in an LFC block imbalance and Area Control Error within the offshore LFC Area. Only the case where the master controller is pushing the imbalance on Elia side is considered further. This will trigger a demand for activation of reserves in the EU balancing platforms Picasso (with full activation time of 5 minutes) and Mari (with full activation time of 12.5 minutes). This will relieve the very fast FCR reserve activations in Continental Europe:

- When connected to the EU balancing platforms, the activation requests of aFRR (based on the offshore area control error) and mFRR (based on the offshore system imbalance) will be netted by the platform algorithms before aFRR and mFRR reserve activations are selected within the regions connected to the balancing energy platforms. The selection of activations will be conducted in function of the available energy bids in the connected LFC Areas and the available transmission capacity between the connected LFC Areas;
- The activation will free up activated FCR and will bring cross-zonal exchanges in line with the outcome of the cross-zonal schedule of all the preceding markets. If the imbalance is resolved with reserve activations in the same LFC Area as with which the imbalance was initially exported in

the real-time operational timeframe, there will be no impact on the physical flows between the offshore bidding zone and the connected regions. In contrast, if the imbalance is resolved with activations in another LFC Area, the flow through the HVDC convertors is adapted accordingly.

- Thereafter, the region can be re-balanced again through the cross-border intraday market, relieving FRR reserve activations by market schedules.

A separate area control error and system imbalance is to be determined for both areas:

- the offshore bidding zone ($SI_{ELIAoff}$, $ACE_{ELIAoff}$)
- the onshore bidding zone (SI_{ELIAon}, ACE_{ELIAon})

In a simplified example (which holds for as long as the allocation in balancing markets applies in an ATC-based logic, which is the current target mode) the balancing market price (set by the cross-border marginal price) will converge over two connected LFC Areas as long as there is remaining transmission capacity between both. Note that this ensures that the adequate price formation in an offshore bidding zone for the preceding timeframe, taking into account network constraints, is hereby extended up to the balancing timeframe. An illustration is given in Figure 131:

- Assume a situation with three bidding zones and three corresponding LFC Areas, e.g. the Princess Elisabeth Zone (PEZ), Belgium (BE) and Denmark (DK) being all part of the same balancing cooperation Mari and Picasso. All LFC Areas will send their available upward and downward bids to the platform. The bids in the Princess Elisabeth Zone are limited to the downward activation of wind power, as there is no other flexible means.

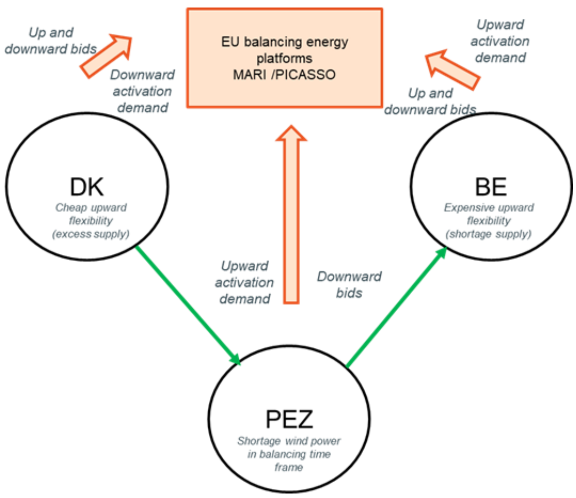

Figure 131 : Iillustrative example of balancing market operations with three LFC areas

- In the situation where both the PEZ LFC Area and the BE onshore LFC Area remain short (e.g. with expensive balancing energy offers), while the DK LFC Area is long (e.g. with cheap balancing energy offers), the following situation can be expected:

    - The shortages in the PEZ will be netted first with the excess in DK after which the cheap additional upward balancing energy can be activated in DK to cover shortages in the PEZ LFC Area, at least as long as there is sufficient remaining transmission capacity. In this example, the netting of imbalances and the activating DK balancing power will be cheaper than activating expensive upward BE balancing energy. It shows how the offshore wind power imbalance can be balanced at the lowest cost.

    - Would it be supported by the available transmission capacity, additional netting of imbalances, and upward balancing energy activations can be activated in DK to cover the shortages in BE. In this example, activating DK balancing power is cheaper than BE balancing energy and the BE onshore imbalances can be balanced at the lowest cost.

The cross-border marginal price will converge between the LFC Areas as long available transmission capacity remains. If transmission capacity limits occur first between DK and the PEZ, the balancing price in PEZ will diverge from DK and converge with the more expensive BE LFC Area. It is even possible that the balancing price converges over the three LFC Areas if no transmission constraints are exceeded. In contrast, it is also possible that the transmission constraint occurs between PEZ and Belgium and that prices in the PEZ diverges from Belgium. The final outcome will depend on the offers and demand for balancing energy and the available transmission capacity between the LFC Areas.

In order to demonstrate the behavior of the balancing market under different conditions, several use cases are presented below for a grid topology with an interconnector of 1.4 GW between the offshore LFC Area and the foreign LFC Area (as foreseen with UK). All newly installed offshore wind power is assumed to be part of an offshore bidding zone, and connected to the offshore LFC Area and the Belgian LFC Area in a hybrid configuration.

Note that all illustrations above and use cases below assume a situation where all LFC Areas are part of the same balancing energy cooperations. This is not necessarily the case, particularly when considering that the Princess Elisabeth Zone is planned to be connected to the UK which is outside of the European Union. It is not certain if the UK will join the balancing cooperations by 2030, or if separate bilateral balancing energy cooperations could be set up. Nevertheless, in the case of Denmark, foreseen to be connected as from 2032 through Triton Link, the different LFC Areas should be part of the same balancing cooperation.

Use case 1: excess wind power during high export conditions to the foreign LFC Area

Figure 132 illustrates a situation with excess wind power in the balancing timeframe when the interconnector is scheduled in full export from the offshore LFC Area to the foreign LFC Area. In this example, the export position follows a scheduled offshore wind power production of 400 MW and an export of 1000 MW from the Belgian onshore LFC Area to the offshore LFC Area.

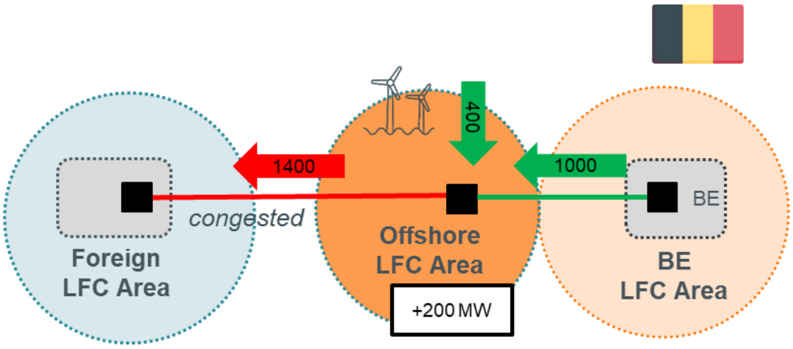

Figure 132 : illustration of a use case with excess wind power (+200 MW) under full export conditions from the offshore to the foreign LFC Area (1000 MW)

Following the available transmission capacity between the Belgian onshore and offshore LFC Area, an excess wind power of 200 MW can be managed through a downward activation of balancing resources available to the Belgian LFC Area (in Belgium, or other connected LFC Areas). These downward activations will reduce the scheduled injection from Belgian onshore to the offshore LFC Area in line with the downward activation of aFRR or mFRR in Continental Europe. Note that the physical flow from the Belgian offshore LFC Area to the offshore LFC Area may already have been reduced in the operational timeframe to balance the HVDC system (in absence of real-time operational exchanges with the foreign LFC Area). The reduction of the import in the balancing timeframe does not impact the physical flows and will just align the cross-border schedules with the physical flows.

Alternatively, balancing resources can be activated in the Offshore LFC Area itself, via a reduction of the offshore wind power injections through downward activation of wind power flexibility. In contrast, no downward balancing resources can be activated in the foreign LFC Area to manage the excess offshore wind power as the available transmission capacity inhibits the increase of the flow from the offshore to the foreign LFC Area. In this use case, imbalance netting and balancing energy activations will be optimized over the connected LFC Areas through the EU balancing platform in function of available liquidity and available transmission capacity[38].

Use case 2: excess wind power during high export conditions to the Belgian onshore LFC Area

Figure 133 illustrates a situation where an excess wind power in the balancing timeframe happens when the hybrid interconnector is already scheduled in full export from the offshore LFC Area to the Belgian onshore LFC Area. In this example, the export position follows a scheduled offshore wind power production of 400 MW and an export of 1000 MW from the foreign to the offshore LFC Area.

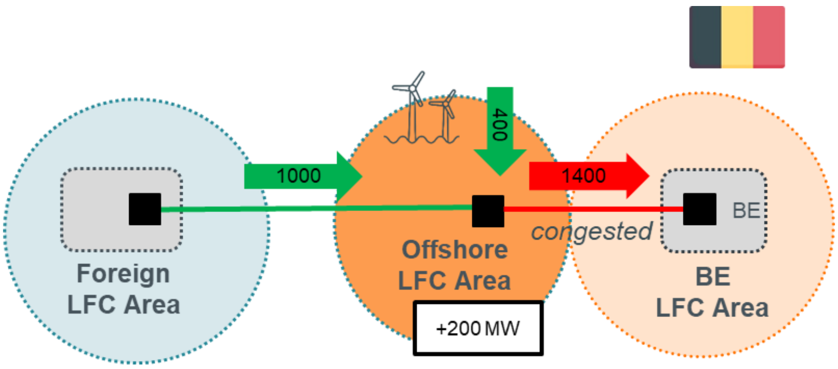

Figure 133 : Illustration of a use case with excess wind power (+200 MW) under full import conditions from the offshore to the Belgian onshore LFC Area

Under these conditions, no downward balancing resources can be activated in the Belgian onshore LFC Area to manage an excess offshore wind power as the available transmission capacity inhibits to increase the flow from the Belgian onshore to the offshore LFC Area.

Yet, similar to the use case 1, balancing resources can be activated in the Offshore LFC Area itself, via the reduction of the offshore wind power injections through downward activation of wind power flexibility.

Alternatively, following the available transmission capacity between the foreign and offshore LFC Area, the excess wind power of 200 MW can be managed through a downward activation of balancing resources available to the foreign LFC Area. These activations will reduce the scheduled injection from foreign to the offshore LFC Area by means of a downward activation of flexibility in the foreign LFC Area.

[38] *As from the commissioning of Nautilus, foreseen in 2030, balancing costs can be optimized over Princess Elisabeth Zone (via the offshore LFC Area), Continental Europe (via the Belgian onshore LFC Area) and the UK. This is only the case with a balancing cooperation between Belgium and UK (via the EU balancing energy platforms or a bilateral cooperation if possible). As from the connection of Triton Link, foreseen in 2031-32, balancing costs can be further optimized with Continental Europe through an alternative transmission path between Belgium and Denmark under the EU balancing platforms.*

This will impact the physical flow from the foreign to the offshore LFC Area unless if the injections were already reduced in the real time operational timeframe via an operational or balancing agreement.

Also in this use case, imbalance netting and balancing energy activations will be optimized through the EU balancing platform in function of available liquidity and available transmission capacity.

Use case 3: shortage wind power during high export conditions to the foreign LFC Area

Figure 134 illustrates a situation where a shortage of wind power in the balancing timeframe happens when the interconnector is scheduled in full export from the offshore LFC Area to the foreign LFC Area. In this example, the export position follows a scheduled offshore wind power production of 400 MW and an export of 1000 MW from the Belgian onshore LFC Area to the offshore LFC Area.

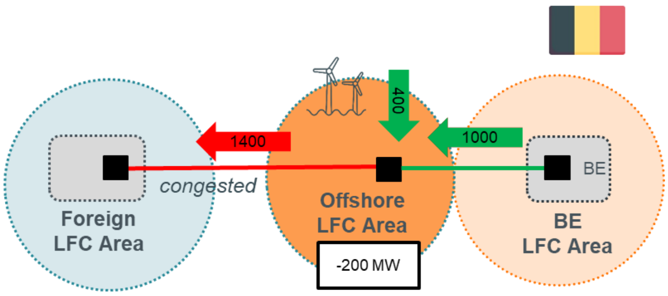

Figure 134 : Illustration of a use case with shortage wind power (-200 MW) under full export conditions from the offshore to the foreign LFC Area

Following the available transmission capacity between the Belgian onshore and offshore LFC Area, the shortage wind power of 200 MW can be managed through an upward activation of balancing resources available to the Belgian LFC Area. These activations will increase the scheduled injection from the Belgian onshore to the offshore LFC Area following the upward activation of aFRR or mFRR in Continental Europe. Note that the physical flow from the Belgian offshore LFC Area to offshore LFC Area may already have been increased in the real time operational timeframe to balance the HVDC system. The new scheduled position will in this case only result in a change of cross-border schedules in the direction of the flow.

In absence of transmission constraints during such conditions, this also means that the required upward reserve capacity, if adequately dimensioned in the Belgian LFC block, is available to cover offshore wind power shortages. This means that under normal conditions, no geographical constraints are to be accounted in the dimensioning. Use case 5 with transmission constraints within the onshore LFC Area will nevertheless highlight a particular situation in which transmission constraints will play a role in the availability of balancing energy.

In this use case, no balancing resources are expected to be available for upward activations in the off-shore LFC Area, at least when assuming no storage, demand or other generation technologies, as only wind power will be installed in the offshore LFC Area. While it is possible to provide upward flexibility with wind power, this is considered very expensive as it requires wind power to continuously generate below maximum generation levels.

Alternatively, following the available transmission capacity between the foreign and offshore LFC Area, the shortage wind power of 200 MW can also be managed through an upward activation of balancing re-sources available to the foreign LFC Area. These activations will reduce the scheduled injection from the offshore to the foreign LFC Area following an upward activation of flexibility in the foreign LFC Area. This will impact the physical flow from the foreign to the offshore LFC Area except if the injections were al-ready reduced in the real time operational timeframe.

Again, imbalance netting and balancing energy activations will be optimized through the EU balancing platform in function of available liquidity and available transmission capacity.

Use case 4: shortage wind power during high import conditions

Figure 135 illustrates a situation where a shortage of wind power in the balancing timeframe happens when the hybrid interconnector is scheduled in full export from the offshore LFC Area to the Belgian on-shore LFC Area. In this example, the export position follows a scheduled offshore wind power production of 400 MW and an export of 1000 MW from the Belgian onshore LFC Area to the offshore LFC Area.

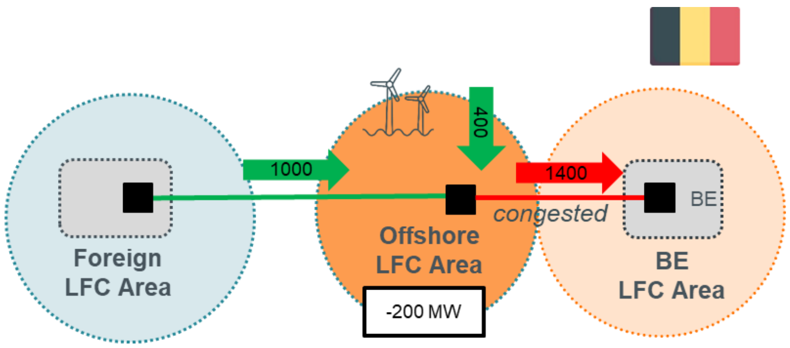

Figure 135 : Illustration of a use case with shortage wind power (-200 MW) under full export conditions from the offshore to the Belgian LFC Area

The possibilities to balance the use case 4 are practically the same as in use case 3. Following the avail-able transmission capacity between the Belgian and offshore LFC Area, the shortage wind power of 200 MW can be managed through an upward activation of balancing resources available to the Belgian LFC Area. As in use case 3, no balancing resources will be available for upward activations in the offshore LFC Area. Finally, the available transmission capacity between the foreign and offshore LFC Area also allows to manage the shortage wind power through an upward activation of balancing resources available to the foreign LFC Area.

Also, in this use case, imbalance netting and balancing energy activations will be optimized through the EU balancing platform in function of available liquidity and available transmission capacity.

Use case 5: transmission capacity limitations below the physical capacity of the HVDC system

Note that even when physical capacity on the HVDC interconnector between the offshore LFC Area and the Belgian onshore LFC Area is available, the available cross-zonal capacity for balancing can be lower as it is subject to the coordinated Core capacity calculation. The limitation may be due to operational limits in the onshore network which can impact the available transmission capacity between the offshore and the connected onshore LFC Areas.

While an excess of wind power, even in absence of balancing or operational cooperation with the connected regions, can always be managed via the measures presented above (downward activation of wind power and the preventive cap), a shortage of wind power cannot be managed without taking additional measures. Indeed, the limited cross-zonal capacity from Belgium to the offshore LFC Area will inhibit the activation of upward flexibility in Belgium to balance the HVDC system and sustain the export to the Foreign LFC Area. This situation is illustrated in Figure 136.

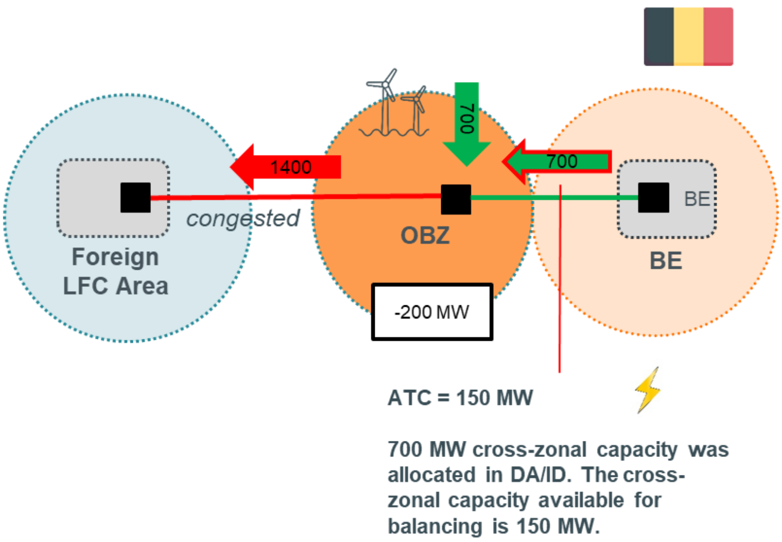

Figure 136 : Illustration of a use case with shortage wind power (-200 MW) under full export conditions from the offshore to the foreign LFC Area (1400 MW)

In the operational timeframe, the export to the foreign LFC Area needs to be curtailed. For instance, when the available transmission capacity between the Belgian LFC Area and the offshore LFC Area is for instance limited to 150 MW, lower than the wind power shortage of 200 MW, as depicted in in Figure 136, there is no other alternative in the operational timeframe than to cut the flow from the offshore LFC Area to the connected region with 50 MW. Note that this can be done via an operational or balancing agreement to be negotiated with the corresponding TSO. Note that it is standard to have such agreement on all interconnectors needed for covering what is happening in the "operational timeframe" (e.g., cable incidents).

In the balancing timeframe, this export restriction will need to be maintained unless the presence of a balancing cooperation allows an upward activation in the connected LFC Area to align cross-border schedules positions with the physical flow on the interconnector. The presence of such balancing cooperation will ensure an efficient activation of balancing resources and give a correct price signal based on the value of upward activation of flexible capacity.

In absence of such balancing cooperation, the export restriction will remain unless the imbalance disappears (e.g. generation re-aligns with the schedules) or is resolved in the intraday market. In such case, the imbalance price in the offshore bidding zone might need to be adapted to reasonable values (to avoid the price cap as shortage cannot be solved, price levels would reach price cap in balancing platforms).

Note that:

- *If a balancing cooperation with UK (via EU balancing platforms or at least cooperate bilaterally) would exist, the dependency on the above- mentioned measures would be reduced;*
- *It is Elia's ambition is to connect Princess Elisabeth Island (and therefore the OBZ) to multiple regions, including Denmark (part of EU Balancing platforms). With more connections, the dependency on the above- mentioned measures is reduced;*
- *Elia also anticipates improvements in capacity calculation as the implementation roadmap in Core unfolds. It is to be noted that the improvements in the pipeline are subject to regulatory uncertainty. Further improvements on capacity calculation can be discussed in due time within Core / EU context but will not be a silver bullet*.

Note that this case is valid for an offshore bidding zone, as well as for a home market configuration. If network limitations follow congestions in the onshore network, the same situations as described in this section unfolds in a home market configuration. However, while the offshore bidding zone ensures a correct price signal, based on the cross-border marginal price, the price signal in the home market solutions will remain equal to the onshore area. This means that a low or negative price in the Belgian LFC block will give wrong incentives to offshore wind power to further reduce injections and worsen the congestion.

5.8.3. Impact on reserve dimensioning

5.8.3.1 Impact on LFC block operational agreement

As explained in Section 5.8.1, an LFC Block is additionally responsible for the dimensioning of FRR. When assuming that the activation of reserve capacity is conducted via two separate LFC Areas, Elia considered two different options (Figure 137).

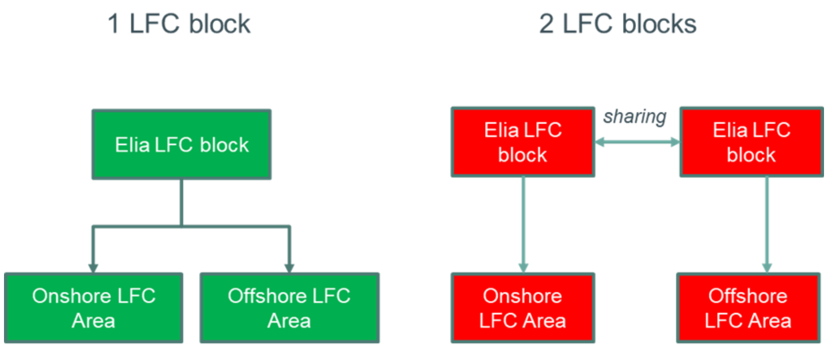

Figure 137 : Options for LFC block structure with an offshore bidding zone

A first option would be to create two LFC blocks which align each with the geographical scope of the Belgian onshore and offshore LFC Area respectively. This would legally imply that each LFC block would specify its own reserve dimensioning methodology in a separate LFC block operational agreement. However, Elia identified several issues with such approach.

First of all, this would result in an over-dimensioning of total reserve capacity as the total reserve capacity needs will be determined as the sum over the two LFC blocks. The current legal framework does not foresee the possibility to net the reserve capacity needs over different LFC blocks. Such netting needs can currently only take place via the framework of reserve sharing, facing stringent limitations following SO Regulation (cf. Article 157). Legal requirements limit the reserve capacity reduction in each LFC block to the difference between the deterministic result (determined by the dimensioning incident) and the probabilistic result (determined by the system imbalances driven by wind power), with an additional constraint of 30% of the dimensioning incident.

Secondly, in the absence of upward flexibility, the offshore LFC block would need to depend entirely on upward reserve capacity exchange where balancing capacity has to be procured abroad in the Belgian LFC block or other connected LFC blocks. However, SO Regulation requires to procure at least 50% of the required FRR capacity in its own LFC block.

On longer term, possible solutions can be sought in a revision of the SO Regulation. But even when assuming that the legal issues will be solved, it will increase the complexity of the dimensioning while maintaining a risk of oversizing the reserve needs and the balancing capacity procurement costs. Furthermore, no economic or operational benefits are identified in such an approach.

The second and better option is therefore to create one LFC block, overarching the two LFC areas, in which LFC block imbalances of the offshore and onshore LFC Area can be netted without legal constraints. Therefore, reserve capacity needs are minimized as offshore wind power forecast errors in the offshore bidding zone are netted with forecast errors of other renewables, and the demand, in the onshore LFC Area.

In contrast to the first option, the legal framework does not formulate constraints on netting within the LFC block. Even if it was needed under particular conditions to take into account geographical limitations with the LFC block following limited network capacity between two areas, this is supported by Article 157. This can for instance be done by means of incorporating network limitations in the dimensioning methodology ensuring the available reserve capacity during network constraints. However such approach would not be required in the Belgian case under normal conditions. Such approach will be followed in the Nordic dimensioning (optimizing reserve capacity over the different LFC areas taking into account network limitations between the areas) while also Germany applies a common dimensioning over the different LFC areas (but does not apply any network limitations in practice).

5.8.3.2 Impact of geographical constraints

It is demonstrated in use case 3 and use case 4 in Section 5.8.2.2 that under normal conditions, network capacity is expected to be available during shortages of wind power to facilitate balancing the offshore LFC area by an upward activation via the Belgian onshore LFC Area. This is the case both during export from the offshore LFC Area to the foreign LFC Area and during export from the offshore LFC to the Belgian onshore LFC Area through. In both cases, the upward reserve capacity foreseen in the Belgian onshore LFC Area through the common dimensioning in the LFC block is available to increase the injections to the offshore LFC Area (or reduce the offtake from the Belgian onshore LFC Area).

In the situation of excess energy, it is demonstrated in use case 1 and use case 2 that under normal conditions, reserve capacity remains available through network capacity with the Belgian LFC area, or through the downward activation of wind power in the offshore LFC Area:

- during export from the offshore LFC Area to the foreign LFC Area, excess wind power can be resolved by means of reducing import through a downward activation via the Belgian onshore LFC Area or a downward activation of the excess wind power in the offshore LFC Area;

- during import from the offshore LFC Area to the Belgian LFC Area, excess wind power can be resolved by means of a downward activation of the excess wind power in the offshore LFC Area.

In the first case, the downward reserve capacity foreseen in the Belgian onshore LFC Area through the common dimensioning in the LFC block will remain available, at least via non-contracted balancing energy bids on offshore wind power. While in the latter, the geographical limitations impact the dimensioning of the reserve capacity in the LFC block, it does not have an impact on the procurement of downward balancing capacity.

It is to be noted that particular conditions with network limitation following onshore internal grid constraints or capacity calculation methods (as presented in Use Case 5 of Section 5.8.2.2) may result in the need to access reserve capacity in the foreign LFC Area which needs to be managed via an operational agreement or balancing cooperation.

5.8.3.3 Impact on reactive balancing

An effect of an offshore bidding zone that is expected to impact dimensioning is that reactive balancing opportunities in an offshore bidding zone are lower compared to the onshore bidding zone.

Wind power plants are assumed to remain responsible for their imbalance (via BRPs), and to be subject to the imbalance price based on the value of balancing energy following the activation of balancing energy through the EU balancing platforms. Wind power plants in an offshore bidding zone can use intraday markets and downward control of wind power (up to real-time) to balance their positions. However, in comparison to wind parks outside the offshore bidding zone, no portfolio advantages currently exist (and thus no possibility to aggregate portfolio imbalances and correct them through other means). Note that:

- In the framework of the electricity market design reform discussion at EU level, it is expected that the intraday cross-zonal gate closure time will be reduced to 30 minutes before real time (hence before the offshore bidding zone would be created)

- Other solutions (pooling portfolio imbalances over bidding zones, facilitate cross-zonal reactive balancing) are not straightforward as they would contradict the congestion management principles according to which an offshore bidding zone is defined.

These reduced reactive balancing possibilities are taken into account in the market performance assumptions reserve dimensioning (Section 5.5) and extreme balancing conditions such as storms and ramps (Section 5.6). Note that the reduced reactive balancing possibilities have a potential incremental effect on the needs for reserve capacity following higher system imbalances, even after netting over the two LFC areas in the Belgian LFC block. However, the effect on balancing capacity procurement and the availability of balancing energy bids, including during storms and ramping events, will likely be mitigated as large part the available flexibility will be offered as non-contracted balancing energy bids in the onshore LFC Area. These volumes will remain available for activation, including during storm and ramping events, and will be accounted via Elia's dynamic procurement strategies to reduce Elia's balancing capacity needs.

5.8.4. Impact on mitigation measures for storms and ramps

This section investigates if an offshore bidding zone can have an impact on the analyses of the need for mitigation measures for storms and ramping events and their design. Similarly to reserve dimensioning, a reduction of reactive balancing capabilities offshore, and therefore of the total balancing market performance, can impact the reserve activation needs of Elia. However, it is expected that this effect is limited when assuming that the largest part of the onshore flexibility which would have been used for portfolio balancing in the home market solution is still made available via balancing energy bids in the EU balancing energy platforms. As the mitigation measures are justified based on the final impact on the area control error of the offshore LFC area, being the result after available reserve activations, no substantial effect is expected on the need for the mitigation measures. If there would be an effect, if e.g., part of the flexibility for portfolio is not able to participate in Mari or Picasso (e.g. following technical constraints of flexible technologies), this will increase the need for mitigation measures.

- **High wind speeds capabilities**

The market design context is not expected to have an impact on the operation of the high wind speed capabilities. In both an offshore bidding zone context and a home market solution, the wind farms have the incentive to mitigate the frequency and impact of storm cut-out events by maximizing injections, also under high wind speed conditions.

- **Ramp rate limitations**

The reduced reactive balancing opportunities in an offshore bidding zone may increase the activation frequency of the ramp rate limitation through increased system imbalances for the offshore LFC Area. However, self-curtailment solutions always remain available under adequate price signals in an offshore bidding zone as such events are expected to relate to low balancing prices.

In order not to unduly affect the situation with an offshore bidding zone, the activation of the ramp rate limitations is foreseen to be triggered by the netted LFC block imbalance, rather than the offshore LFC Area imbalance alone. In other words, the activation trigger is the same irrespectively of the market setup. This ensures to take into imbalance netting between the onshore and offshore LFC Area before activating the measure.

Note that situations where such netting would not be possible are already covered by the preventive cap. Indeed, full export conditions from the island to Belgian resulting in network congestions will activate limits for injecting excess energy for the offshore wind farms and no additional ramp rate limitations are needed.

- **Preventive curtailment**

Similarly to ramp rate limitation, reduced reactive balancing opportunities in an offshore bidding zone may increase the activation of the preventive curtailment measure due to the limited options of BRPs to manage offshore wind power after the intraday market gate closure. However, it can be expected that a large part of the flexibility available in a home market solution for portfolio balancing will remain available for the cross-border balancing energy market when an offshore bidding zone is put in place. As the activation of the preventive curtailment takes into account all the available flexibility in the LFC block before triggering an activation of the measure, there should not be a large impact on the activation frequency and on the impact of the preventive curtailment measure.

The activation of the preventive curtailment is thus not expected to be fundamentally impacted by an offshore bidding zone as it is foreseen to be triggered by the total available flexibility in the LFC block, similar to a home market solution.

5.9. Implementation roadmap

Based on the results presented in this study, Elia recommends the implementation of four mitigation measures before the connection of the foreseen new offshore wind farms in 2029 (Figure 138). Three of the measures (High wind speed technologies, Ramp rate limitations and Preventive curtailment) will deal with the system risk imposed by storm and ramping events while a fourth measure (Preventive cap) concerns the implementation of a measure related to the hybrid asset topology.

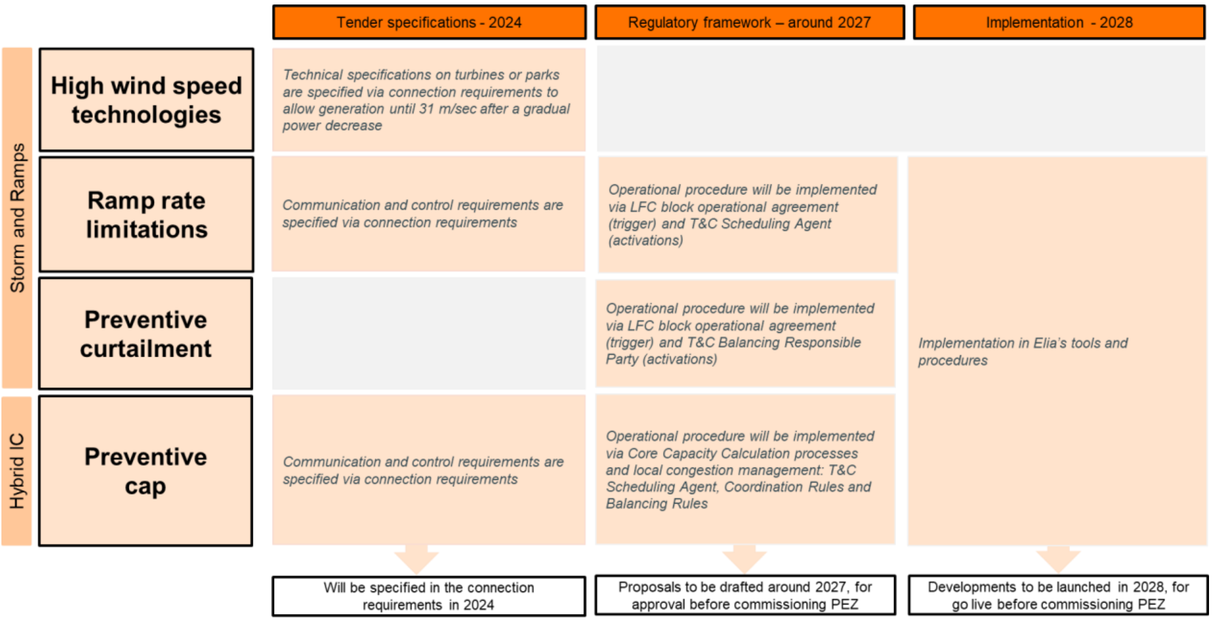

Figure 138 : Indicative implementation roadmap of the recommended mitigation measures

The High Wind Speed (HWS) capabilities require wind turbines to be capable to maintain generation until wind speeds of 31 m/s with a gradual ramp down. The specifications will be defined in the connection requirements published before the first tendering phase in 2024. The requirements can (if requested by market parties) allow wind farms to demonstrate equal capabilities on wind park level. No operational procedures are foreseen for the operation of this High Wind Speed capability as once this capability is installed, it is expected that wind farms have all incentives to operate this technology to maximize the generation of their offshore wind park.

The **Ramp rate limitation** requires wind farms to limit the upward generation ramp of wind power plants after a close-to-real-time signal of Elia during large excess imbalances in the system. The technical specification to ensure the control and monitoring will be specified in the connection requirements to make sure the wind farms demonstrate the ability to adapt injections upon a signal received from Elia. The operational procedure will be specified at a later stage in the regulatory framework: the trigger will be implemented via a modification of the LFC block operational agreement while the reaction of the wind park can be implemented via the Terms and Conditions Scheduling Agent. Note that these modifications will require consultation of the market parties and approval by CREG. The principles of the procedure and the parameters that will be proposed will be based on the results of this report.

The **Preventive curtailment** requires wind farms to reduce injections under the capabilities following wind speed conditions. The activation of the measure will be communicated in intraday when predicting unmanaged portfolio imbalances following storm or downward ramping events while the system is expected to have insufficient flexibility to cope with the foreseen shortages. This measure does not require additional technical capabilities on top of the general connection requirements. Similar to the ramping rate limitations, the operational procedure will be specified at a later stage in the regulatory framework. The trigger will be implemented via the existing exhausted reserve procedure in the LFC block operational agreement while the activation can be implemented via the Terms and Conditions Balancing Responsible Parties, in line with the existing “Storm Procedure”. These modifications require consultation and regulatory approval. The principles of the procedure that will be proposed will be based on the recommendation presented in this report.

The **Preventive cap** is needed to deal with the hybrid topology. Similar to the ramp rate limitations, it requires specifications in the connection requirements to ensure the ability to receive control signals in the real time (in this case communicated as an injection limit) sent by Elia upon which to adapt wind power injections. Also here the operational procedure themselves will be specified at a later stage in the regulatory framework for congestion management. This concerns the Coordination Rules (as well as the Terms and Conditions Scheduling Agent and Terms and Conditions Balancing Responsible Parties). Also here, consultation of the market parties and regulatory approval of the modifications will be needed. The principles of the procedure that will be proposed will be based on the recommendations presented in the report.

Elia foresees to submit the proposals for regulatory approval around 2027, after public consultation. This ensures sufficient time for implementation of the operational procedures and required applications before the commissioning of the first farms in 2029. Elia does not exclude drafting the modifications earlier in time but clarifies that launching the work too early is not deemed efficient in view of adapting the proposals to the latest system evolutions. The developments required by Elia will be launched around 2028 to be ready for the commissioning of the first wind parks.

6. Annexes

6.1. Appendix 1: Technical Report MOG II System Integration – 2022 update

The full report is available on the webpage of this public consultation.

6.2. Appendix 2: Table of Figures

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