March 2025

Operational Policy Roadmap

2025-2035

EirGrid SONI

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1. Background, Context and Drivers

Background and Context

EirGrid and SONI are securely operating the All-Island system with world-leading variable renewables penetration, primarily from wind energy. In 2023, 41% of energy used on the island came from renewable resources. In 2024, the All-Island system continued to accommodate up to 75% of instantaneous generation from non-synchronous resources (mainly wind, solar and HVDC interconnection).

In 2024, EirGrid and SONI confirmed the relaxation of an operational constraint from 8 to 7 minimum large conventional generation units as an enduring operational policy. Additionally, six (6) synchronous condenser projects were procured through the LCIS framework to enhance our capacity to support RES and reduce our dependency on conventional units for several system services. To meet the ambitious decarbonisation targets in the years ahead, the electricity system will need to accommodate greater amounts of renewable energy. Operational constraints will need to be further relaxed to facilitate another step change in accommodating renewable energy resources.

Shaping our Electricity Future

The governments of Ireland and Northern Ireland, respectively, have introduced legislation relating to climate action. Energy and electricity usage will be core elements of the respective climate action legislation and implementation plans. In 2023, EirGrid and SONI updated the Shaping Our Electricity Future roadmap – to allow EirGrid and SONI to enhance our capability in markets, networks, engagement and operations. One of the key commitments in the Shaping Our Electricity Future roadmap was to develop an Operational Policy Roadmap. This roadmap outlines the key actions in the operational policy space that will be required to deliver on the climate action targets while continuing to securely operate the all-island electricity system.

The All-Island power system will undergo radical transformation between now and 2030, and beyond to 2035, including: the connection of at least two new HVDC interconnectors (to Great Britain and France), large offshore wind farms and solar generation, hydrogen energy production, demand response and energy storage innovations, coupling to European markets and anticipated market evolution, as well as significant growth in demand driven by electrification of society end-use and large energy users, e.g., data centres. The roadmap will aim to chart a pathway for the evolution of operational policy to facilitate these radical transformations while maintaining and enhancing security of supply, reliability and resiliency for customers on the island of Ireland.

This operational policy roadmap updates our plan to 2035 to accommodate continued growth in variable, non-synchronous renewable generation. It outlines the context, drivers, timelines, milestones, actions, and stakeholder impacts that are needed in each operational policy area to achieve the ambition of the governments' decarbonisation targets for the electricity sector.

Evolution of the Shaping Our Electricity Future and Operational Policy Roadmap documents.

Drivers of Change: Key Drivers for the Operational Policy Roadmap

The significant transformation to the All-Island system is driven by several key factors, highlighted here. Central to these changes is the targeted reduction in overall CO_2 emissions in each jurisdiction, with the ambitious goal of achieving up to 80% of electricity annually from renewable sources by 2030. The following key drivers are crucial to understand to accommodate the dynamic nature of the future energy system, and to ensure a resilient and sustainable electricity system.

1 New Technologies and Innovative Solutions

- Availability of new and **novel technological solutions** that unlock new possibilities while requiring new strategies to manage and adequately integrate onto the grid.
- **Increased inverter-based resources** connected to the grid.
- Increased **need for network and demand flexibility**.

2 Demand Growth

- Total All-Island energy use is expected to grow from **45.1 TWh in 2024** to **58.4 TWh in 2032**[1].
- All-Island transmission peak demand forecast to grow from **7.5 GW in 2024** to **8.9 GW in 2032**.
- Demand is **expected to grow even further beyond 2035** as electrification intensifies.

3 Network Evolution

- At least **one new HVDC interconnector (including Celtic to France)**[2], a second North-South interconnector and **over 370 network reinforcement projects** are planned for the All-Island system.
- New **offshore network developments** to accommodate offshore wind development.
- Significant increase in **smart network devices.**

4 Generation Capacity Growth

- Total **All-Island RES-E generation capacity**, including onshore wind, offshore wind and solar PV, is expected to **grow from around 9.2 GW in 2023 to around 27.6 GW in 2030**[1].
- Deployment of **significant storage volumes**, including long duration energy storage (**LDES**).

5 Affordability and Competitiveness

- Implement **Future Arrangements for System Services (FASS) by the end of 2026.** This includes a system services daily auction mechanism (DASSA).
- Couple to **European markets by the end of 2026**, post-connection of Celtic HVDC.

[1] EirGrid and SONI Generation Capacity Statement 2023-2032 – median scenario (appendix 1 & 4, link).
[2] A new HVDC interconnector to GB (Greenlink) became operational in 2025.

1 Key Drivers - New Technologies and Innovative Solutions

New Technologies and Innovative Solutions

Grid-forming Technology (GFM)

- Establishment and implementation of the concept in codes and standards by introducing definitions and requirements for grid-forming inverter-based resources (GFM).
- Improve confidence in the technology through simulations and live trials.

Network Flexibility Technologies

- Test and implement new network technology solutions (e.g., Dynamic Line Rating (DLR), Power Flow Controllers (DPFC), etc.) to increase utilisation of the existing network and accommodate new HVDC interconnectors and large offshore wind farms.

Low Carbon Inertia Services (LCIS)

- The next phase of low carbon system services will be needed to reach the 2030 targets.
- LCIS will dramatically decrease the dependency on the conventional units for crucial system services like inertia, reactive power support and short-circuit contribution.

Demand Response

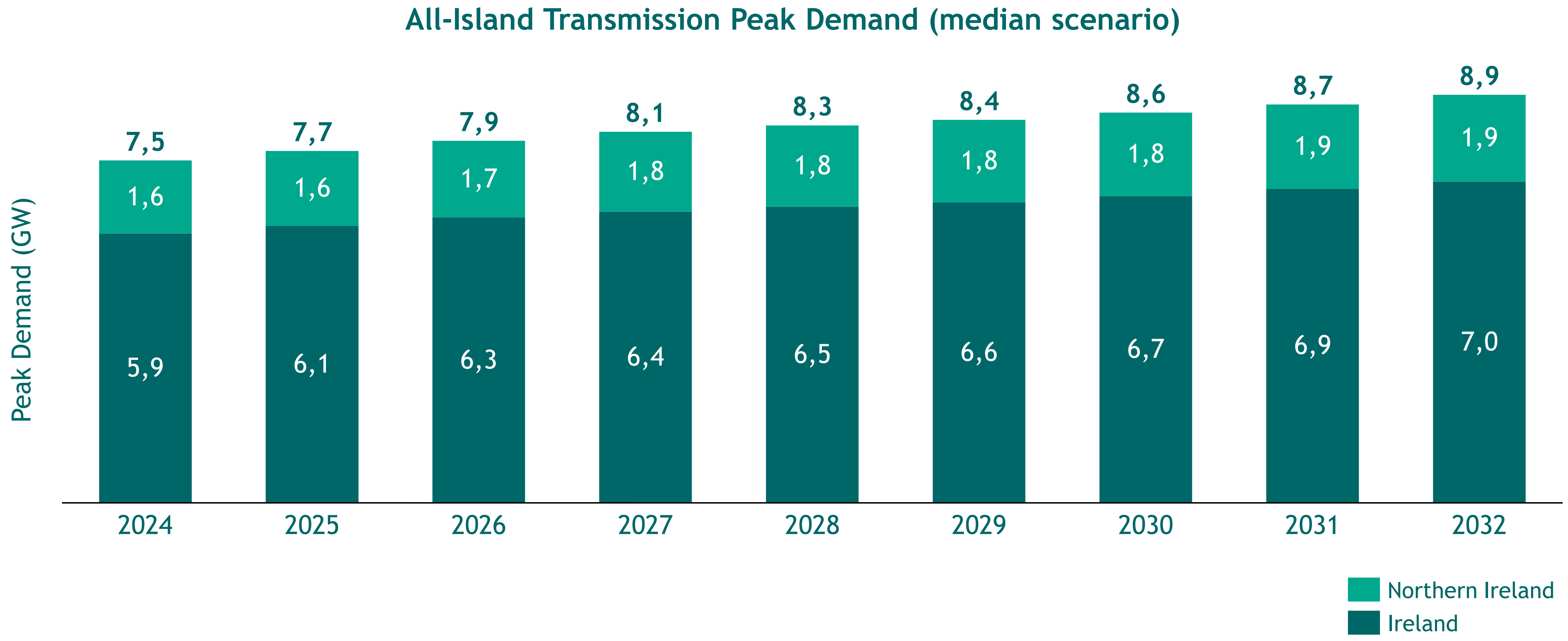
- Incentivise demand customers to become more flexible, considering grid code and control implications.
- Demand response and demand aggregators, and dynamic pricing are expected to play an increased role on the grid with a new EU network code on demand response coming into force.

Energy Storage

- Expand the existing utilisation of energy storage, e.g., battery energy storage systems (BESS) and long-duration energy storage (LDES), through enhanced TSO scheduling and dispatch capabilities and evolve the system services arrangements to allow for enhanced frequency management.

2 Key Drivers - Electricity Demand Growth

For the median demand forecast as set out in the Generation Capacity Statement 2023-2032[1], the All-Island transmission peak power demand is projected to grow from 7.5 GW in 2024 to 8.9 GW by 2032. There is expected to be an increase in large energy users, demand response, electrification in society, prosumer flexibility and demand aggregators.



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[1] EirGrid and SONI Generation Capacity Statement 2023-2032 – median scenario (p. 123 link).

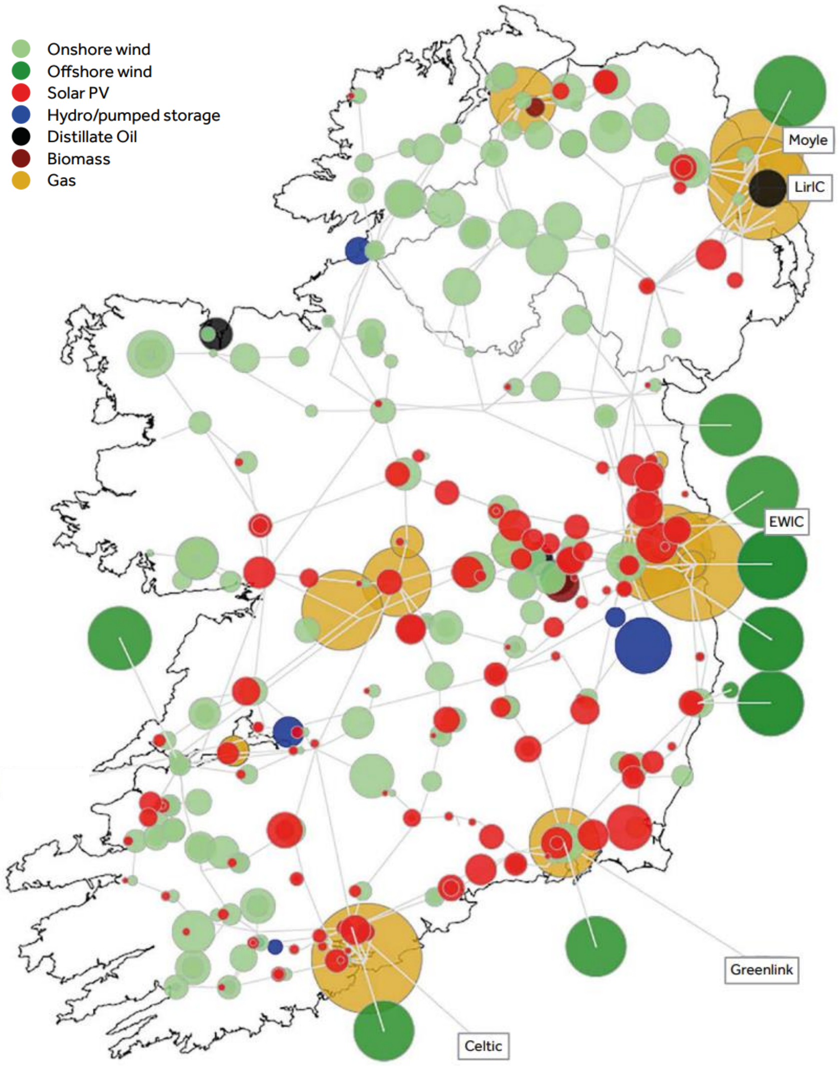
3 & 4 Key Drivers – Electricity Network Expansion and Generation Growth

Generation Growth

This map shows the potential spatial distribution of generation by 2030. The assumed locations for future connections of renewables were informed by a range of information sources such as consultation feedback, grid connection applications, outcomes of auctions and projections of available grid capacity. These locations are subject to change; they will be updated as part of future revisions of Shaping Our Electricity Future to reflect the best available information.

Network Expansion

In 2035 there is expected to be a second North-South tie-line in operation between Ireland and Northern Ireland, and at least four (4) HVDC links to the All-Island system (Moyle, EWIC, Greenlink, Celtic) with a total capacity of 2.2 GW. There is expected to be significant levels of offshore wind connected. These new onshore wind, offshore wind and solar generation resources will drive the need for new transmission infrastructure, smart devices and flexibility.



SOEF 1.1 (2023) Anticipated Generation Spatial distribution in 2030

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5 Key Drivers – Enhance Affordability and Competitiveness

Future Arrangements for Systems Services (FASS)

The Electricity Balancing Guidelines and the Clean Energy Package put in place requirements to procure ancillary services through market-based methods on a short-term basis to the extent possible and in the most economic manner possible. Additionally, these regulations require reserve ancillary services or balancing capacity to be procured no later than a day ahead. In the context of the need to establish an economically efficient framework to continue to procure ancillary services to support further enhancements to system operation, to facilitate decarbonisation targets and renewable ambitions, the System Services Future Arrangements (SSFA) project was formally launched by the SEM Committee in July 2020. The objective of this initiative is: “to deliver a competitive framework for the procurement of System Services, that ensures secure operation of the electricity system with higher levels of non-synchronous generation.” [1]


SEM committee

SINGLE ELECTRICITY MARKET COMMITTEE

System Services

Future Arrangements

High Level Design Decision

SEM-22-012

14th April 2022


SEM committee

SINGLE ELECTRICITY MARKET COMMITTEE

Future Arrangements for System Services

DASSA Market Design

Decision Paper

SEM-24-066

16 September 2024

Couple to European markets

The Celtic Interconnector is a planned 700MW DC interconnector linking the Single Electricity Market (SEM) and France (FR). The target date for commissioning and market entry is Q4 2026. The implementation of the Celtic Interconnector will physically reintegrate the SEM with the European Energy Markets, following isolation as a result of Brexit.[2]

The Celtic Interconnector will deliver a wide-ranging package of benefits to consumers and businesses in both Ireland and France, with positive impacts on electricity pricing, Ireland’s security of electricity supply, and our national transition to a low-carbon economy. By facilitating electricity flows throughout Ireland, France and continental Europe, the Celtic Interconnector will enable consumers to benefit from a more open electricity market. This increased competition in the Irish electricity market will apply downward pressure on the cost of electricity, leading to lower prices for consumers. [3]

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[1] SEM Committee, System Services Future Arrangements Phase III: Detailed Design & Implementation SEM-23-103 (link).
[2] SEM Ex-Ante Market Design For EU Re-Integration, 29 May 2023 (link)
[3] Celtic Interconnector Project Step 3 – Consultation Response Document, Summer 2019 (link)

2. Operational Policy Framework

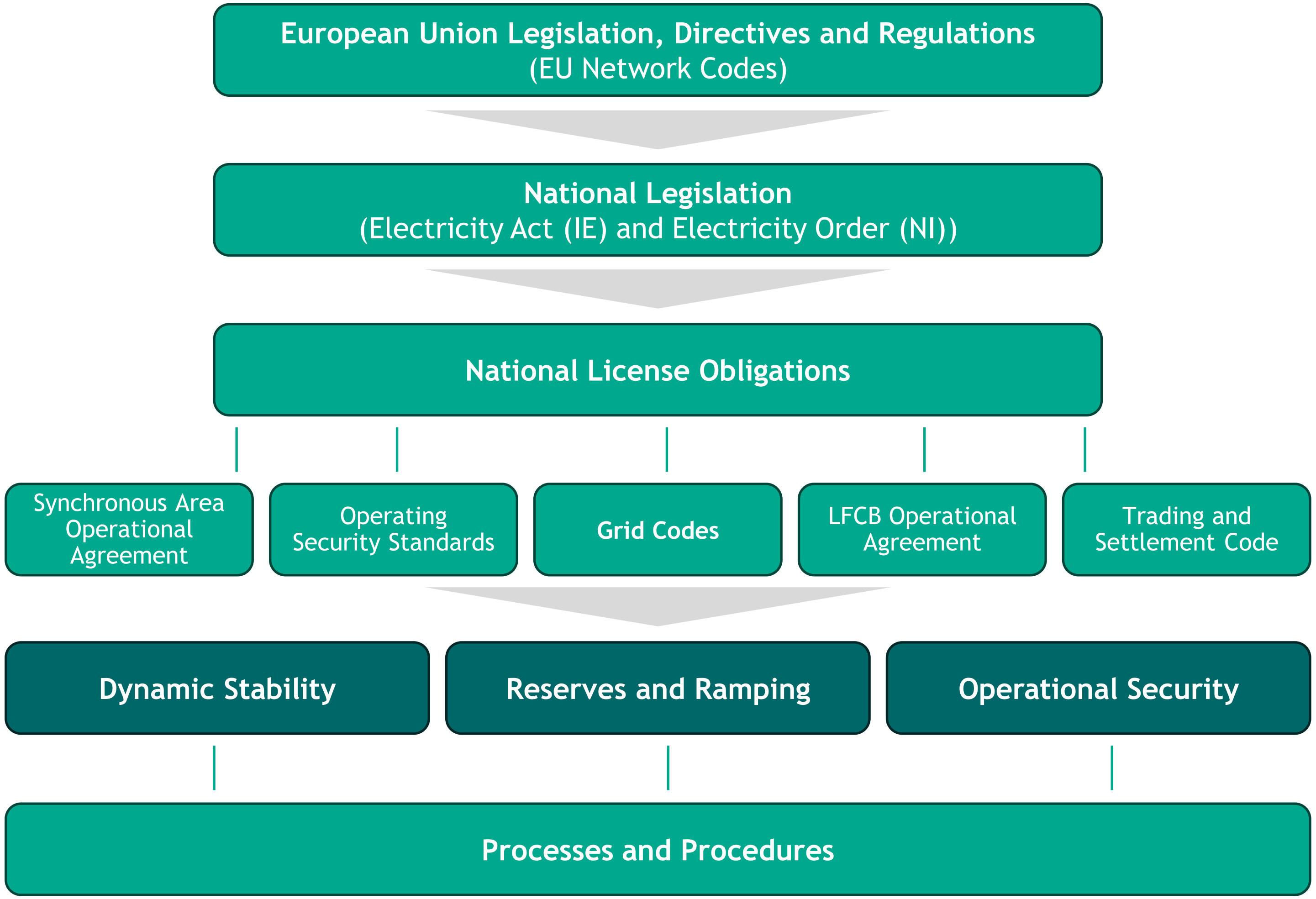
Operational Policy Framework - Overview

Framework Overview

The EirGrid and SONI operational policies sit within an overarching framework, governed by relevant European and National Legislation and Network Codes, and guided by published codes and standards.

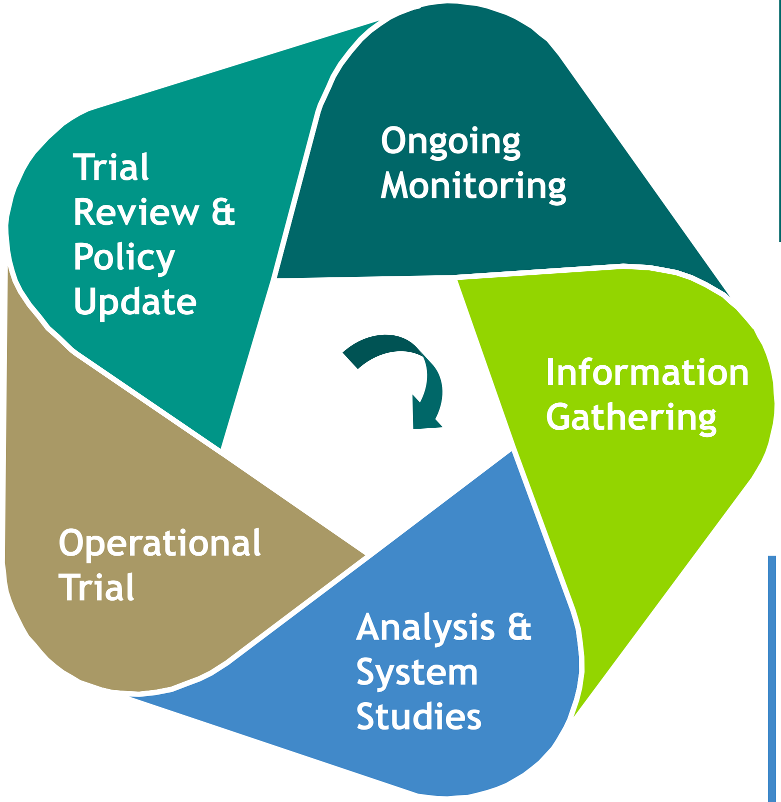
Operational Policy is driven by the need to operate the transmission network securely and reliably, within asset and connected entities' limits. This must be achieved while managing the market in a transparent manner as per the Trading and Settlement Code. The synchronous area and load frequency control block (LFCB) operational agreements between EirGrid TSO and SONI TSO govern how both entities interact.

All Operational Policies are linked to processes and procedures, detailing how the policies are implemented and maintained in practice in real-time operations and when planning the system.



Operational Policy Change Process

EirGrid and SONI's joint **Operational Policy Review Committee (OPRC)** governs the process of operational policy changes. The OPRC comprises members with extensive experience and expert knowledge of system operations. The members consider the proposed changes, review all related materials/reports, and approve or reject the proposed changes following an operational trial period and assessment of same. Operational policy in EirGrid and SONI is monitored, reviewed, and updated according to a **five-stage continuous cycle process**, described below.



01 Ongoing Monitoring

In the Ongoing Monitoring phase, EirGrid and SONI monitor the system parameters and analyse events and disturbances to assess system performance and generator compliance relative to operational policy parameters and metrics.

02 Information Gathering

During the Information Gathering stage the current status of the policy and parameters are assessed, and consultation is held with operations specialists on the drivers, requirements and need for changes.

03 Analysis & System Studies

At the Analysis & System Studies stage subject matter experts and operations policy specialists study the system under an extensive and detailed range of conditions. They study the impact of the proposed policy change and make recommendations on the conditions of the operational trial. The OPRC approve or reject the proposed trial, based on the studies and in-depth discussions.

04 Operational Trial

If the OPRC grant approval, an operational policy trial is commenced with strict operational criteria and parameters to be monitored, including hours of operation. The trial may be suspended at any time by operations staff if adverse impacts arise during the trial.

05 Trial Review & Policy Update

If the trial period of operation passes without adverse impacts, subject matter experts will study the results of the trial parameters and criteria. An in-depth examination of the trial period is carried out and reported on to the OPRC. The conditions and events during the trial are examined to determine if any trial related issues arose. The OPRC reviews the outcome and report and decides whether to either:

1. Cease the trial noting adverse impacts.
2. Continue the trial if there is insufficient evidence. Gather more relevant data points and information to support decisions.
3. Approve the proposed operational policy change as the enduring operational policy.

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Operational Policy Framework - Definitions and Current Requirements

Key Areas of Operational Policy

The operational policy roadmap is divided up in three (3) main sections:

- **Dynamic Stability**
- **Reserves and Ramping**
- **Operational Security**

These sections together cover the full spectrum of operational policy at EirGrid and SONI. It is important to note, however, that these three sections are merely useful 'buckets' to categorise different aspects of operational policy for understandability and reporting purposes.

Many of the underlying drivers, challenges and opportunities identified in individual sections may influence other aspects of system operation as well. These interdependencies are highlighted wherever relevant in the document.

Policy Area	Policy & Constraints	Definition	2024 Status
Dynamic Stability	Inertia	The minimum level of kinetic energy stored in rotating plant operating on the system. Inertia comes from synchronous generation, motor load and synchronous condensers.	23 GWs
	Rate of Change of Frequency (RoCoF)	How fast the frequency moves when subjected to an event that results in a mismatch between generation and demand.	1 Hz/s
	System Strength	Definition of the relative strength of the system in terms of short circuit strength, stability, retained voltage and others.	In development
	Minimum Number of Conventional Units (MUON)	Constraint on the system that specifies a minimum number of conventional units on-load required to be synchronised in Ireland and Northern Ireland.	7 (3 NI / 4 IE)
	System Non-Synchronous Penetration (SNSP)	A measure of the non-synchronous generation on the system at an instant in time. It is the ratio of the real-time MW contribution from non-synchronous generation and net HVDC imports to demand and net HVDC exports.	75 %[1]
Reserves and Ramping	Fast Frequency Response (FFR)	Response by resources and service providers in the 2 to 10 second range.	Dimensioning in development
	Primary Operating Reserve (POR)	Response by resources and service providers in the 5 to 15 second range.	75% LSI[2]
	Secondary Operating Reserve (SOR)	Response by resources and service providers in the 15 to 90 second range.	75% LSI[2]
	Tertiary Operating Reserve 1&2 (TOR)	Response by resources and service providers in the 90 second to 20-minute range in two tranches.	100% LSI[2]
	Replacement Reserve (RR)	Response by resource and service providers in the 20 minute to 4-hour range.	100% LSI[2]
	Ramping Margin (RM)	The level of dispatchable generation/demand available to mitigate very fast ramps and demand and RES forecast errors. There are 1-, 3-, and 8-hour ramping services.	Explicitly scheduled
	HVDC Ramping Rates	The rate of change of HVDC interconnector active power flow. This is an All-Island measure which includes the ramp rates for Moyle in NI and EWIC in IE.	5 MW/min per interconnector
Operational Security	Voltage Management	The ability to securely operate the system by controlling the voltage, within a specified range, pre and post contingency.	Defined in Operating Security Standards
	Thermal Security Management	The ability to securely operate the system by controlling the pre and post contingency thermal loading within the ratings of the transmission system plant.	Defined in Operational Security Standards
	Short Circuit Management	Assessment of equipment duty performed to ensure all plant is within its making, breaking and withstand ratings for the prospective short circuit current calculated.	Defined in Operational Security Standards

[1] 80% operational trials expected to be finalised in 2025.
[2] Referring to largest single infeed (LSI).

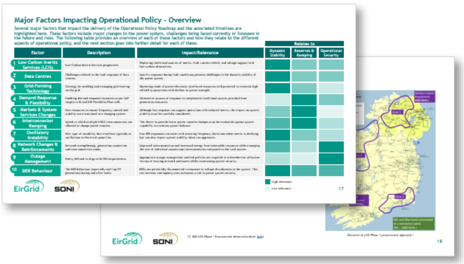
Roadmap Structure Overview

Major Factors

Overview of major factors impacting operational policy, including significant changes, risks and opportunities, such as:

- **Low-Carbon Inertia Services**
- **Data Centre Fault Ride-Through Issues**
- **Grid-Forming Strategy**
- **Demand Response**
- **Markets & System Services Changes**
- **Interconnector Ramping**
- **Fast-responding Batteries**
- **Network Change and Risk-based Approaches**
- **Distributed Energy Resources (DER) Behaviour**

Additionally, an overview page linking these factors to operational policy areas is included.

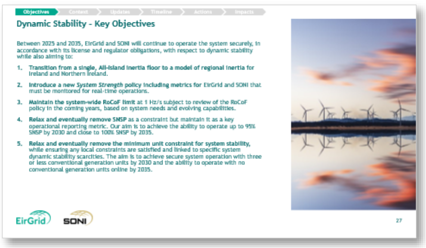


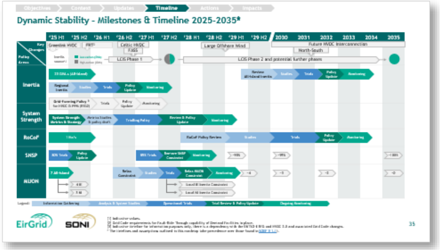
Operational Policy Areas - Section Contents

For each of the three (3) main operational policy areas there is a detailed section included containing the following contents to provide a holistic overview of the aims, actions, challenges and impacts associated with this aspect of operational policy:

Objectives & Context → Updates → Timeline 2025-2035 → Actions → Stakeholder Impacts

- **Objectives & Context**: **Objectives** and **context** regarding this aspect of operational policy
- **Updates**: Updates since the previous OPR iteration in 2022.
- **Timeline 2025-2035**: Updated timeline showing the **milestones** and **actions** associated with this aspect of operational policy.
- **Actions**: Further detail on timeline actions.
- **Stakeholder Impacts**: Overview of stakeholder impacts.





3. Major Factors Impacting Operational Policy

System Level Overarching Dependencies and Risks

The Operational Policy Roadmap is an **ambitious vision for how policy should evolve through the decade to support the decarbonisation targets**. The All-Island power system currently requires a balanced portfolio of new capacity to address the heightened risk of Loss of Load Expectation (LOLE) in Ireland and ensure continued security of supply. The medium- and long-term milestones and targets are tentative and will be dependent on an extensive series of studies, reviews, monitoring processes and rollout of innovative technologies that determine the future operational policy and constraints. Successful implementation of actions and enablers outlined in this roadmap is reliant on regulatory decisions and funding.

Performance of System Users

The ability to run operational trials and to change policy will be dependent **on the evolving performance of system users** (in particular, Demand Facilities and Distributed Energy Resources). The development and application of new user performance requirements will be key to the TSOs being able to deliver the operational policy changes outlined in this document.

Network and System Services Development

Timely delivery and commissioning of system services providers, new flexible generation, major infrastructure projects (e.g., second North-South Interconnector) and other transmission reinforcements are required to assist with future challenges and meet the decarbonisation targets.

Security of Supply

Operational trials will be **dependent on system operational conditions and the need to ensure continued security of supply to customers in Ireland and Northern Ireland**. Conditions on the grid may influence the ability to effectively conduct trials as planned.

Operational Capability

Operational capability must be continuously uplifted to align with the **new challenges and requirements** introduced by the increased complexity of system operations. For example, enhanced operational forecasting, observability, monitoring and control capabilities will be required.

Operational Studies

Analysis will be the key factor to determining the precise constraint values and policy direction. The capability to perform advanced analysis (e.g. EMT simulations for IBR dominated networks) must be further developed and increased automation will be necessary to carry out relevant analyses more frequently to inform the system constraints. The **availability of these capabilities remains critical to the delivery of the roadmap**. To ensure high accuracy of the simulation studies, an important aspect is the capability to adequately model the performance of new and emergent technologies. Codes and standards must be updated to reflect the requirement for provision of representative models.

Major Factors Impacting Operational Policy - Overview

Several major factors that impact the delivery of the Operational Policy Roadmap and the associated timelines are highlighted here. These factors include major changes to the power system, challenges being faced currently or foreseen in the future and risks. The following table provides an overview of each of these factors and how they relate to the different aspects of operational policy, and the next section goes into further detail for each of these.

			Relates to		
Factor	Description	Impact/Relevance	Dynamic Stability	Reserves & Ramping	Operational Security
1 Low Carbon Inertia Services (LCIS)	Low-Carbon Inertia Services programme.	Replacing traditional sources of inertia, fault current infeed, and voltage support with low-carbon alternatives.			
2 Data Centres	Challenges related to the fault response of data centres.	Specific response during fault conditions presents challenges to the dynamic stability of the power system.			
3 Grid-Forming Technology	Strategy for enabling and managing grid-forming on the grid.	Operating mode of power electronic interfaced resources with potential to maintain high reliability operations with decline in system strength,			
4 Demand Response & Flexibility	Enabling demand response resources as per CAP targets in IE and DfE Flexibility Plan in NI.	Alternative sources of response to complement traditional sources provided from generation resources.			
5 Markets & System Services Changes	New resources to ensure frequency control and stability are maintained in a changing system.	Although fast response can support operations with reduced inertia, the impact on system stability must be carefully considered.			
6 Interconnector Ramping	Speed at which multiple HVDC interconnectors are allowed to change power transfer.	The desire to provide faster power transfer changes must be evaluated against system capability to maintain system balance.			
7 Oscillatory Instability	New type of instability that manifests typically as oscillations in electrical quantities.	Fast IBR responses can assist with arresting frequency deviations when inertia is declining but can also impact system stability when too aggressive.			
8 Network Changes & Reinforcements	Network strengthening, generation connection and interconnection works	Improved interconnection and increased energy from renewable resources while managing the size of individual connections/interconnectors compared to the total system.			
9 Outage Management	Policy defined to align with OSS requirements.	Appropriate outage management and risk policies are required to achievebetter utilisation factors of existing network and assets whilst maintaining system security.			
10 DER Behaviour	The DER behaviour (especially roof-top PV generation) during and after faults	DERs are potentially disconnected in response to voltage disturbances in the system. This can increase contingency sizes and poses a risk to power system security.			

High relevance

Low relevance

1 Low Carbon Inertia Services (LCIS)

LCIS Phase 1 & 2 Procurement

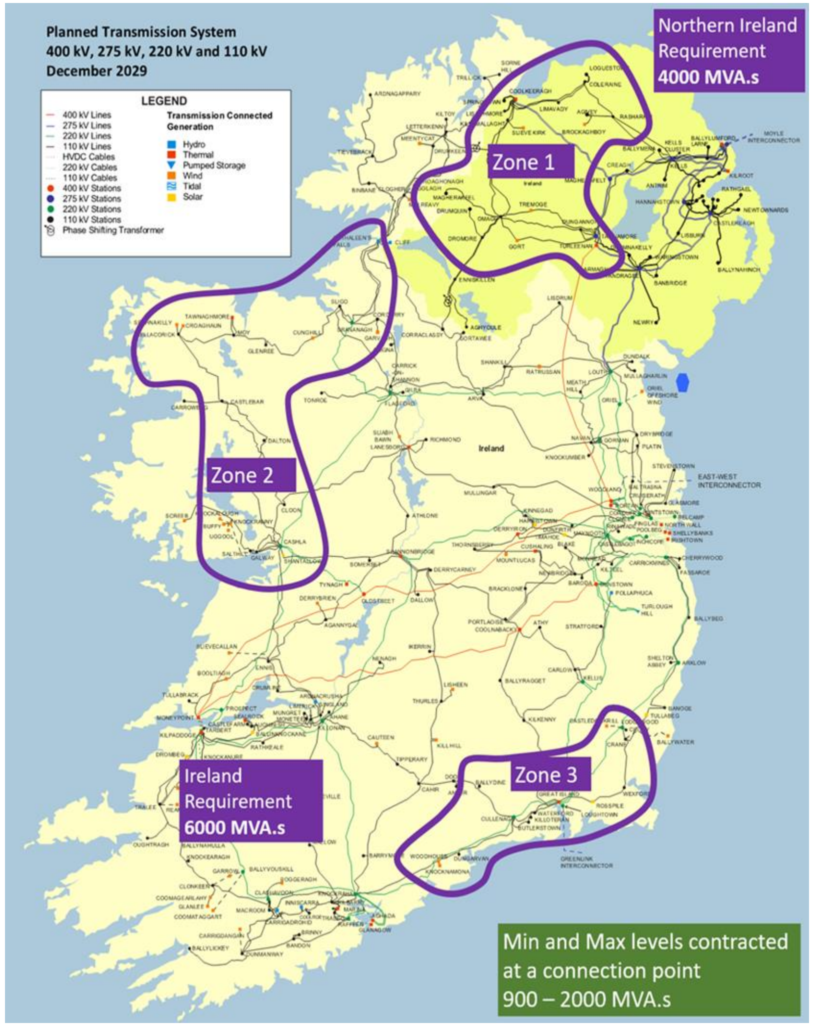
The outcome of extensive simulation studies have informed the requirement for a system service comprising the provision of synchronous inertia, reactive power support and short-circuit contribution to alleviate future system operation challenges.

The **Low Carbon Inertia Services (LCIS) programme was designed to deliver this capability**, with the first phase focusing on procurement of low-carbon inertia from technologies like synchronous condensers. This programme will contribute to a reduction in the minimum number of conventional units required to be running, increased renewables integration, reduction in production costs, reduction in carbon emissions and enhanced security of supply.

The first phase of LCIS procurement has now been successfully completed and will contribute significantly to meeting EirGrid and SONI 2030 decarbonisation targets.

- Phase 1 successfully contracted a total volume of 10,963 MVA.s of inertia, with 6,963 MVA.s in Ireland and 4,000 MVA.s in Northern Ireland, which equates to ~45% of the current All-Island inertia floor. This service was contracted across six (6) individual large devices, of which five (5) are to be located within the incentivised zones (with the highest derived benefits from such services).

This successful first LCIS procurement will be **followed-up by a second phase, LCIS Phase 2**, expected to get underway in 2025. The volume and technology requirements for LCIS Phase 2 are currently being assessed.



Overview of LCIS Phase 1 procurement approach.[1]

[1] SEM LCIS Phase 1 Procurement Information Note (link).

2 Data Centres

Data Centre challenges with Fault-Ride-Through

Data centres have been a significant addition to the demand profile of the grid (in Ireland especially) in the past decade. In the operational context, data centres are large power electronic-interfaced loads with a relatively static load profile.

Data centre demand can be very sensitive to dips in the system voltage experienced at the data centre point of connection to the transmission grid. These voltage dips can originate from relatively far away from the data centre demand itself. The protection functions implemented to safeguard power electronic components of data centres are set to trigger automatic shifting of load onto alternative, back-up electricity supply whenever they sense a disturbance.

These protection functions are not defined in the Grid Code or under the control of the TSOs. In combination with large transmission contingencies (such as the loss of a HVDC interconnector), the consequential disconnection of large amounts of one specific load type (e.g., data centre loads) could result in difficult-to-contain system disturbances.

New Grid Code Performance Standards

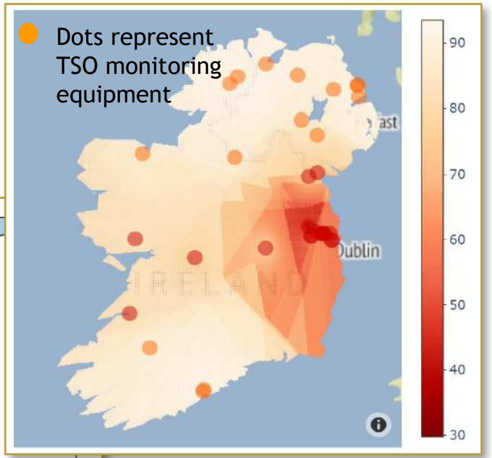
Traditionally, the Grid Codes' development revolved around the connection conditions and performance requirements for generators, with less detailed and stringent requirements for loads. With the advent of large power electronic-interfaced loads, power systems worldwide are reviewing their connection conditions and performance requirements for data centres and other similar loads.

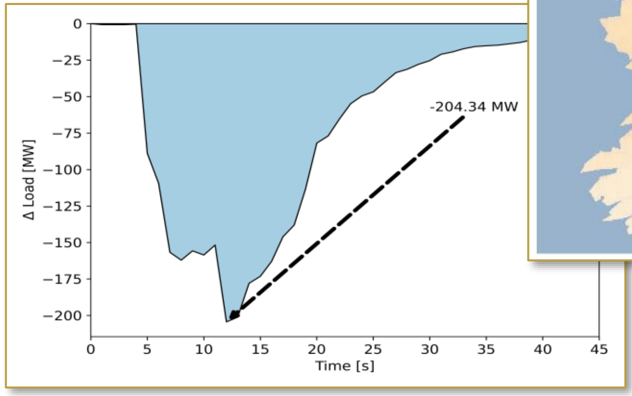
At the time of publishing this update to the Operational Policy Roadmap, new performance requirements for loads are under development by the TSOs. **Implementation of Fault Ride-Through (FRT) capabilities for loads are key to the TSOs being able to deliver the operational policy changes outlined in this document. The timelines for these changes to FRT requirements are highlighted on page 54 and 55 in further detail.**

Projected Data Centre Growth Rates

Current consumption: In 2023 Data centres consumed21% of all metered electricity from the grid in Ireland, up from 18% in 2022. By **2032, 30% of all electricity demand is expected to come from data centres and other new large energy users**. In the median scenario: energy demand is forecasted to increase 43% by 2032, with data centres being a key driver.

Disturbance propagation (contour map) and collective Data Centre Response (13 Dec. 2022, 220 kV fault in Dublin.





[1] Ten Year Generation Capacity Statement 2023-2032 (p. 16, link).

3 Grid-Forming Technology

Grid-Forming Technology and Policy Development

Grid-forming technology (GFM) is a control technique that allows IBRs to act as a voltage source and operate in a stable manner when connected to relatively weaker areas of the grid (i.e. areas of the grid that are remote from synchronised conventional generation).

This technology allows for an IBR to regulate the power by controlling directly the voltage at its terminals and provide a reference voltage for other nearby IBRs operating in grid following mode, and for IBRs to self-synchronise to the grid. These traits could be very helpful from a system operation perspective with high shares of inverter-based renewables (e.g., Power-Park Modules (PPM) as per EU Requirements for Generators v2.0) and HVDC interconnectors (e.g., Celtic) connected to the grid, when managed well.

Whilst the technology maturity has increased, there is **no well-established industry definition for the GFM concept**.

To consider GFM alongside other LCIS technologies for provision of System Strength, enhanced study capabilities must be developed. The need for advanced modelling capabilities is driven by the new system dynamic behaviour when operating with fewer synchronous machines and multiple IBRs running fast and sophisticated controls. As a result, and depending on the system traits delivered, GFM is strongly interlinked with system strength.

To effectively integrate GFM technologies on the All-Island system, improved understanding and management capabilities of operational challenges related to these GFM must be developed, especially with regards to:

- Maintaining GFM operation under extreme and degraded system operation scenarios;
- Maintaining GFM operation at both ends of HVDC interconnectors;
- Provision of detailed, validated models and simulation capability for GFM based assets.
- The provision of inertia and damping and current limited operating conditions.
- Stability when operating in GFM mode in relatively stronger areas of the system; and
- Interoperability with nearby network and controllers.

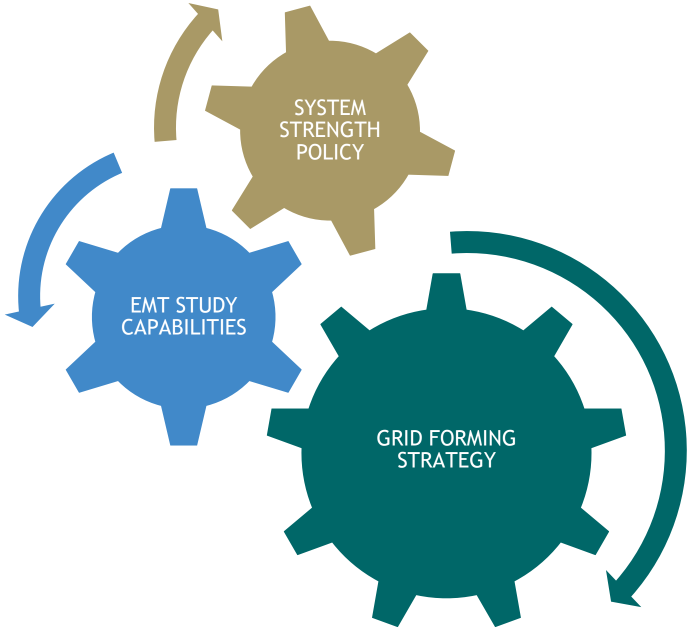


Illustration of interaction between GFM, system strength and need for EMT modelling capabilities.

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4 Demand Response & Flexibility

Demand Side Flexibility in Context

Demand side response and flexibility are enablers of an efficient market and transmission system. In a market and operational context, having the capability to shift demand from periods of high network stress or utilisation to periods of relatively lower capacity, is highly advantageous. It means expensive generation may not have to be dispatched to meet peak demand and curtailed energy from renewable energy resources can be better utilised.

Demand Side Flexibility Targets

Electrification of society is continuing at pace, in particular transport and domestic space heating.

The Climate Action Plan of Ireland 2024 (CAP24) set a **target for demand side flexibility of 20-30% by 2030**, from a baseline of approximately 5% in 2024.

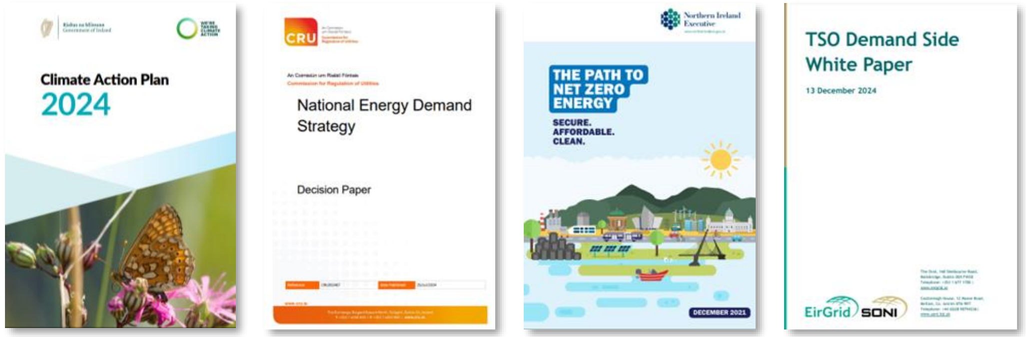
The CRU in Ireland published its National Energy Demand Strategy (NEDS) in 2023 setting out a pathway to achieving the target through:

- **Smart Meters and Service** – Enabling time of use tariffs and smart services for domestic and commercial use to encourage implicit demand side response;
- **Demand Flexibility and Response** – Enabling procurement, markets, products, and growing participation of demand side response and storage, including LDES; and
- **New Large Energy Demand Connections** – Offsetting grid impacts of large energy users.

In Northern Ireland, DfE is currently finalising its Flexibility Plan. SONI is proactively supporting this work and will also be undertaking the assessments defined in Article 19E of Reg 2019/943 which will be used to inform the formal flexibility objectives for NI.

Operational Impacts

With the right arrangements and focus on how different types of demand customers could meet various power system needs, demand side response and flexibility could play an important role in contributing to meeting various power system needs and decarbonisation. In this way, these services could make an important contribution to achieving the 2030 renewable energy and emissions targets. Such flexible resources also have the potential to contribute to improving the TSOs' ability to operate the power system securely at very high levels of variable renewable generation. If demand side response and flexibility are to become a more significant part of market, however, changes to rules, operational policies, systems and forecasts may be required to enable seamless utilisation of this flexibility in the demand.



From left to right: Ireland Climate Action Plan 2024 (link), CRU NEDS (link), DfE Energy Strategy for Northern Ireland (link), and EirGrid and SONI developments for demand side response and flexibility through a Demand Side White Paper (link).

5 Markets & System Services Changes

Future Arrangements for Systems Services (FASS)

SEM Committee outlined in its High-Level Design Decision on the System Services Future Arrangements the need to **refine the existing DS3 arrangements, implemented in 2016 and designed to facilitate integration of new and existing technologies** while maintaining a resilient power system, and move toward a day-ahead auction-based procurement of appropriate system services.

Day Ahead System Services Auction (DASSA)

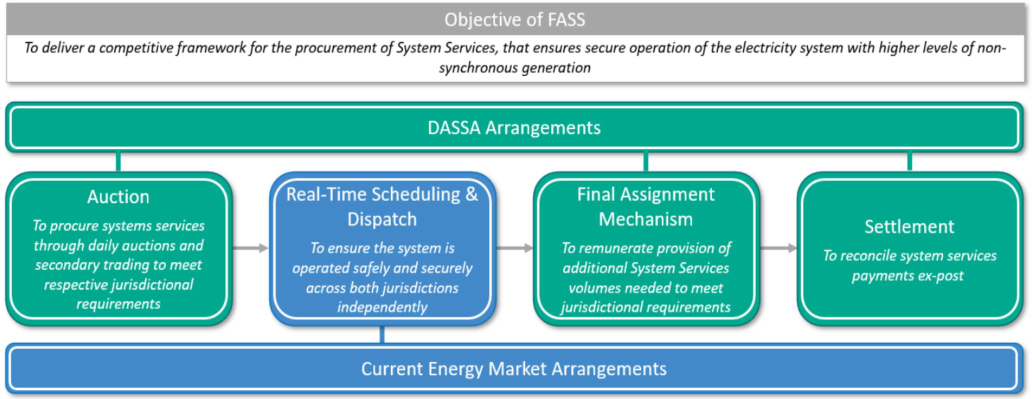
As part of FASS, a programme to develop the DASSA is ongoing, for delivery by end 2026. DASSA will, among other things:

- Redefine the loss of the largest infeed/outfeed as a ***reference incident*** (subject to SEMC approval) that must be secured for with reserves;
- Introduce 'downward' reserve products (FFR, POR, SOR, TOR1, TOR2, RR) that will mirror the existing 'upward' products;
- Fully define Fast Frequency Response (FFR) requirements including; response times, frequency deadbands, trajectories, reserve step sizes and reserve step triggers, that will be configurable by the TSOs;
- Maintain minimum reserve requirements within each jurisdiction to ensure the security of Ireland and Northern Ireland power systems following a 'system split' event;
- Require more accurate system models for use in simulation analysis to determine the response needs.

Scheduling and Dispatch Programme (SDP)

The advent of DER and BESS requires enhanced visibility and control in operational timescales. EirGrid, SONI and SEMO are currently developing and delivering the Scheduling & Dispatch Programme to ensure this visibility and control is available to system operators. This programme includes, among other things:

- Treatment of new non-priority dispatch renewable generation;
- Wind and solar dispatchability enhancements;
- Energy storage systems capability;
- Synchronous condenser capability;
- Fast frequency response (FFR) capability; and
- Reserve services capability dispatch and scheduling from new providers.



Overview of the DASSA programme design (link).

6 & 7 Interconnector Ramping & Oscillatory Instability

HVDC Interconnectors and Offshore Wind Ramp Rates

Multiple large (relative to the All-Island system) HVDC interconnectors are due to be connected. The HVDC voltage-source converter (VSC) technology has the capability to change power transfer output and direction very fast. This has the potential to introduce operational challenges, especially system-wide frequency control related, but also localised voltage control issues during power wheeling.

- **The All-Island system must increase its capability to handle fast changes in power transfers across HVDC interconnectors**. Due to time zone differences, different market arrangements, and different ramp rate regimes compared to Great Britain, HVDC interconnectors to continental Europe introduce higher probability of more frequent changes in output than existing HVDC interconnectors.
- Larger power systems with multiple resources that can achieve fast ramping rates can better accommodate full power swings on HVDC interconnectors (change from full import to full export) in short periods of time. **As the All-Island system is a relatively small system, for system security considerations, the power system needs to restrict fast ramping rates** in order to manage operational risks.
- **Large offshore wind farms can have a similar impact** and the way in which their power output is allowed to ramp must be carefully considered, especially in situations when the power output is resumed following curtailment.

Oscillatory Instability including Fast-Responding IBR

Power systems operating with high penetration of IBRs have been experiencing **occasional instances of inverter-driven instability**. This new type of instability tends to manifest itself through **low-frequency, large-amplitude oscillations of electrical quantities**.

There have been observed cases of large oscillations leading to widespread disconnection of other network connected devices before any remedial actions could be implemented in operational timescales.[1] These scenarios impose elevated risks to security of supply.

Typically, these inverter-driven instability events are attributed to incorrect or unsuitable controller settings. **With less synchronous machines active on the grid and changes of system resource mix and topology, occurrences of these events could increase. This requires the TSOs take appropriate mitigation actions.**

Although modern fast-responding IBR technology, e.g., in use for BESS, can provide fast acting capability, a **very aggressive response from IBRs in certain locations of the system can lead to unwanted degradation in power system operating conditions**. This must be appropriately managed in through applicable codes and standards.

The All-island system already experienced concerns related to the characteristics of response coming from IBRs. The settings that determine the response characteristics of IBRs must be carefully defined and tested before implementation. System strength and locational specific configurations may lead to different settings and response to limit the potential for unwanted interactions.

[1] High Inverter-Based Resource Integration: The Experience of Five System Operators, IEEE Journals & Magazine (link).

8 & 9 Network Changes and Reinforcements & Outage Management

Network Changes and Reinforcements

Several major changes to the network configuration and new reinforcements are foreseen to the All-Island system over the coming years.

The deployment of multiple HVDC interconnectors and large offshore wind farms across the east and south coast must be accompanied by strengthening of the power system. The large rating of these new installations relative to the power system and their capability to change power output fast affects all three pillars of operational policy:

- **On dynamic stability -** Frequency, voltage, oscillatory instability;
- **On reserves and ramping -** Higher volumes of reserves and response that need to be carried, and limits on ramping of these resources; and
- **Operational security -** Changing short-circuit levels and impacts on voltage and thermal loading of transmission assets.

Timely delivery of critical projects like the 400 kV North-South Interconnector are essential for relaxing All-Island transmission constraints. The potential for an All-Island system separation event following a credible contingency, currently determines multiple system constraints, e.g.:

- **Dynamic stability -** Higher inertia levels and RoCoF to be maintained;
- **Reserves and ramping -** Levels of reserves and response carried and their locational distribution; and
- **Operational security -** Short-circuit, voltage and thermal constraints in the form of TCGs.

Outage Management and Risk-based Operations

Under the current grid configuration and operational requirements to maintain safe and secure operation, **high power output levels from renewable generation are sometimes curtailed due to limitations in the thermal loading capability of the network assets.**

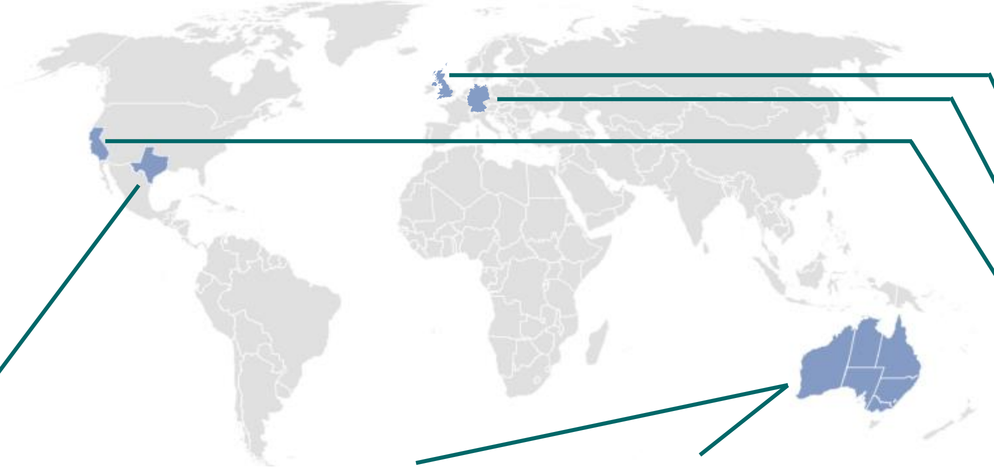
To temporarily relax constraint levels until network upgrades are delivered, the following mitigation solutions are being explored:

- Review of thermal rating schedules to make use of emergency ratings;
- Trial dynamic line rating technologies to unlock weather-dependent capacity on existing lines;
- Implementing active network management schemes; and
- Actively utilising risk-based approaches in operating the grid.

More generally, **the integration of risk-based approaches in the operation of the power grid and outage management could unlock significant additional transmission capacity in areas where it is needed most.**

The introduction of risk-based approaches in grid operation and outage management is in line with European regulation regarding system operation (SOGL). These approaches require high level of coordination between the TSOs, with the DSOs, and TAO and connected parties to ensure confidence in models and data to accurately assess risks.

10 DER Behaviour During and After Faults



Impact on Under Frequency Load Shedding (UFLS)

Under Frequency Load Shedding (UFLS) schemes are a critical safety net to stabilise balance between generation and load. They are required during events with severe lack of generation. However, DER can exacerbate some aspects of dynamics that require UFLS. **DER creates uncertainties, and therefore can compromise the efficacy of traditional UFLS** in three ways:

1. Reduction in the amount of net load available for shedding under the UFLS;
2. Reverse flows on UFLS circuits. Under these circumstances, the operation of UFLS relays acts to disconnect circuits that are acting as net generators, accelerating frequency decline rather than arresting it; and
3. Significant proportions of installed distributed PV (DPV) systems display under-frequency disconnection behaviour.

ERCOT[1] and AEMO[2] have experienced significant challenges from DER impacts on UFLS schemes during critical contingency events in recent years.

DER Disconnection after Transmission Faults

The emerging global issue of **large-scale distributed roof-top PV (DPV) disconnection in response to voltage disturbances** will likely impact the All-Island system. Disconnection of a large proportion of DER poses a risk to power system security and can increase contingency sizes. AEMO[3] and CAISO[4] are at the forefront of DPV challenges, with TSOs in multiple other countries[5] observing this phenomenon too.

This primarily necessitates mandating appropriate fault-ride-through requirements for DPVs through relevant standards and codes. It is important to set these requirements adequately and proactively as updating them later on can be costly. It also requires potentially increases in system services, changes to network constraints, and other operating processes to maintain system security.

The All-Island TSOs and DSOs have been working together to understand and address these potential issues.

[1] 'Odessa disturbance' in Texas (link).
[2] Multiple generator trip event combined with high DPV infeed resulting in issues with UFLS in Australia (link).
[3] 2018 Queensland & New South Wales frequency disturbance-event (link).
[4] Multiple faults causing large-scale PV disconnections in California (link)
[5] 2019 disruption causing DER loss in GB (link), German 50.2Hz problem (link)

4. Dynamic Stability

EirGrid SONI

Dynamic Stability – Key Objectives

Between 2025 and 2035, EirGrid and SONI will continue to operate the system securely, in accordance with its license and regulator obligations, with respect to dynamic stability while also aiming to:

1. **Transition from a single, All-Island inertia floor to a model of regional inertia** for Ireland and Northern Ireland.
2. **Introduce a new *System Strength* policy including metrics for** EirGrid and SONI that must be monitored for real-time operations.
3. **Maintain the system-wide RoCoF limit** at 1 Hz/s subject to review of the RoCoF policy in the coming years, based on system needs and evolving capabilities.
4. **Relax and eventually remove SNSP** as a constraint but maintain it as a key operational reporting metric. Our aim is to achieve the ability to operate up to 95% SNSP by 2030 and close to 100% SNSP by 2035.
5. **Relax and eventually remove the minimum unit constraint for system stability,** while ensuring any local constraints are satisfied and linked to specific system dynamic stability scarcities. The aim is to achieve secure system operation with three or less conventional generation units by 2030 and the ability to operate with no conventional generation units online by 2035.

Dynamic Stability Definition

Dynamic Stability

Dynamic stability refers to the ability of a power system to maintain stable operation in the face of disturbances, such as sudden changes in generation or load, faults, or equipment failures.

Dynamic stability can broadly be categorised and defined in the following five (5) categories.

The following slides detail the individual metrics and policies EirGrid and SONI utilise to maintain all areas of dynamic stability on the All-Island system.

Dynamic Stability

Frequency Stability	Maintain and restore equilibrium between the demand and supply after subjected to contingency or disturbance.
Transient and Small-Signal Stability	Maintain synchronism when subjected to large severe and small disturbances.
Voltage Stability	Return to acceptable steady voltage levels at all busbars in the system after being subjected to a disturbance.
Inverter-driven Stability	Avoid undamped oscillations due to interactions between IBR units and between IBR and other power system components.
Resonance Stability	Avoid unwanted interaction between IBR controls and resonances present in the network.

Dynamic Stability Metrics

The following four key metrics are currently in use to measure and assess dynamic stability across the All-Island power system.

Inertia

The inertia of the power system refers to the ability of the system to oppose changes in system frequency due to the resistance imposed by the large rotating masses of the synchronous machines. The inertial energy has an important role in the frequency control process. The natural resistance of the synchronous machines to a change in speed assists with keeping the power system frequency close to its nominal frequency of 50 Hz.

$$H = \frac{1}{2}\frac{J\omega_o{}^2}{S_n}$$

J is the total moment of inertia
ω_0 is the angular frequency
S_n is the total power

SNSP

The System Non-Synchronous Penetration (SNSP) and the Minimum Number of Conventional Units On (MUON) are system constraints introduced to ensure enough synchronous machine capacity is maintained to a level that guarantees a secure and safe system operation. SNSP metric was introduced following analysis performed as part of Facilitation of Renewables (FoR) studies in 2011 and has been regularly refined. It refers to the ratio of non-synchronous supply infeed on the grid at any given time.

$$SNSP\ [\%] = \frac{non\text{−}synchronous\ generation + net\ imports}{demand + net\ exports}\ x\ 100$$

RoCoF

The Rate of Change of Frequency (RoCoF) is a measure of how fast the frequency moves when the system is subjected to an event that results in a mismatch between generation and demand. RoCoF is inversely proportional to the system inertia; the lower the inertia, the higher the RoCoF.

$$RoCoF = \frac{f * Power\ Loss}{2(H_{total} - H_{power\ loss})}$$

f is the frequency
H_{total} is total system inertia
$H_{power\ loss}$ is lost inertia due to power loss

Note: This calculation method is instantaneous, not average RoCoF. It does not consider the effect of fast frequency response from IBR or the inherent response from frequency and voltage dependent load.

MUON

The minimum number of conventional units on (MUON) constraint was introduced to ensure enough large synchronous units are operating to preserve the voltage control capability and maintain a minimum level of system inertia, this is independent of the inertia constraint.

Currently, the constraint is set to a minimum of 4 large conventional units in Ireland and 3 in Northern Ireland to satisfy this constraint (from a selected list of generators considered large), while trials are being considered to reduce this number.

The Need for Dynamic Stability Operational Policy Changes

Several key reasons for why there is a need for changes in operational policy with regards to dynamic stability.

1 Need to disaggregate global constraints

- Global constraints (SNSP, MUON) have served a valuable purpose for system stability and RES integration. However, these constraints are not targeted enough to deal with more localised issues. A new approach is needed for the transition to 2035.
- There is a need to link market constraints more explicitly to physical system scarcities in specific areas, to free up capacity wherever available.

2 Opportunity to incorporate synchronous condensers, grid-forming and other emergent technologies

- Synchronous condensers and GFM are an alternative solution to assist with inertia, reactive power range, fast voltage control and fault current infeed. Performance requirements must be incorporated into codes and standards and policy updated with operation guidelines.
- Introduce definitions and requirements to specify IBR Grid-Forming performance.
- Create the framework for other innovative solutions and emergent technologies to be deployed

3 Enable new ways to manage system strength and enhanced system monitoring

- Requirement for enhanced dynamic stability monitoring, particularly in weakly interconnected areas of the network.
- New policies are required to assess network stability that account for very high-IBR integration and lack of conventional generation.
- New metrics for system strength are required in order to meaningfully measure performance in this area beyond just fault levels.

The Need for Operational Policy Changes – To Target Regional Issues

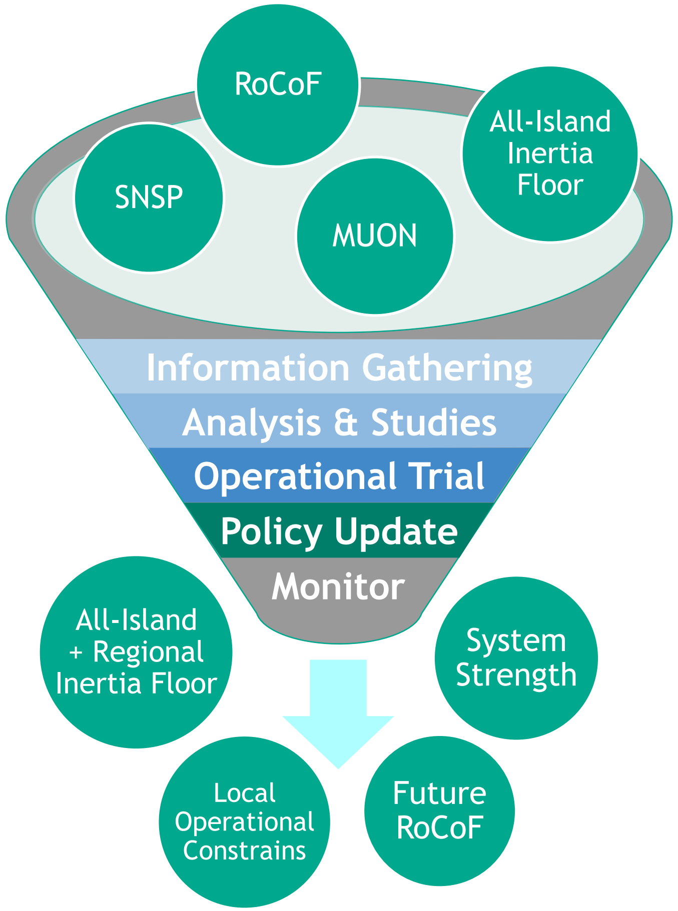
To enable safe and secure All-Island system operation with the identified changes over the coming decade, addressing operational challenges in a more localised fashion can offer an effective solution. For example, SNSP emerged as a metric from the 2010 Facilitation of Renewables report. It was intended to act as temporary, global operational limit until thorough analysis was performed to better understand the risks and implement mitigation solutions. However, to operate the system of the future, to the levels needed to achieve decarbonisation targets, global constraints that limit non-synchronous resource output will need to evolve to targeted local constraints. Relaxing this constraint over time will allow more RES generation to be operated at the same time in the All-Island system, contributing to RES integration goals.

Now:

SNSP, All-Island Inertia and **MUON** are global constraints and metrics. Introduced to ensure enough **synchronous generator traits are maintained** to a level that guarantees a secure and safe system operation.

Future:

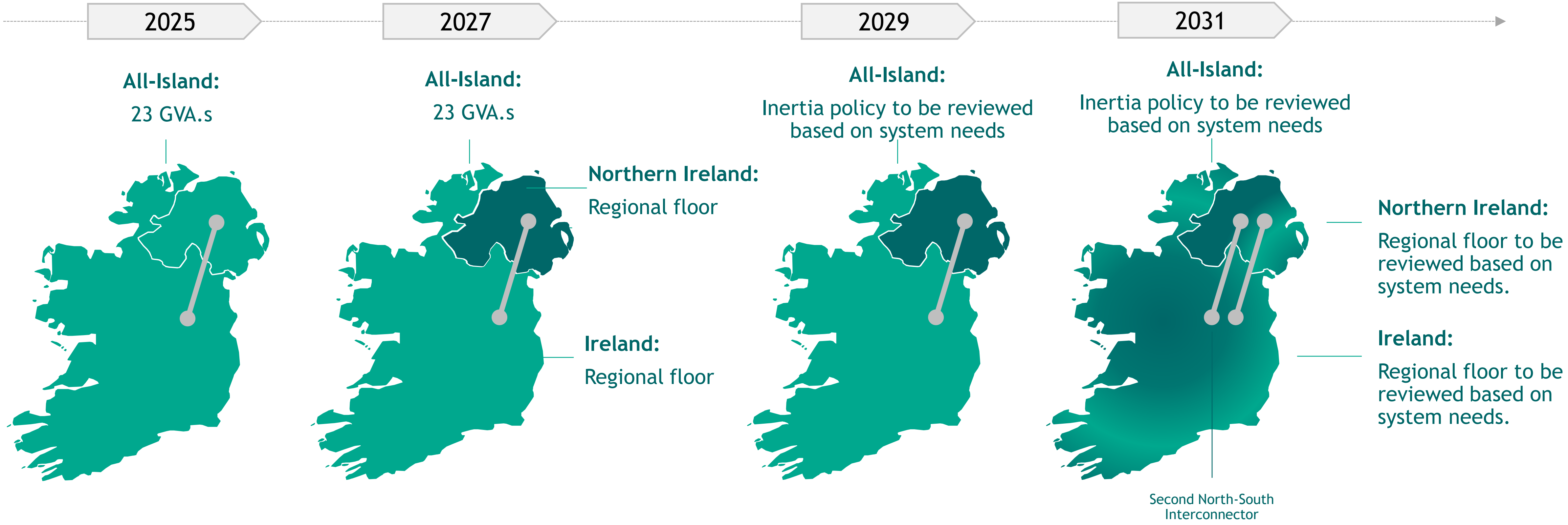
EirGrid and SONI aim to develop **operational constraints to target regional and local network constraints and scarcities**. This will involve development of a new system strength policy, a new regional inertia framework and the relaxation, and eventual removal of the SNSP and MUON constraints, while maintaining them as reportable operational metrics.



EirGrid SONI

The Need for Operational Policy Changes – Regional Inertia Floor

There currently is an All-Island inertia floor of 23 GVA.s in place that must always be maintained on the island for dynamic stability. There is also a requirement for a minimum number of large conventional units to be on (MUON) in both regions, to mitigate the risk of the loss of the North-South tie-line. EirGrid and SONI will move to a model of a regional inertia floor, considering the planned go-live of the second North-South interconnector in 2031. This move, and the delivery of the LCIS programme, will enable reducing MUON constraints across Ireland and Northern Ireland while ensuring dynamic stability and operational security for the loss of the tie-line. This approach will be re-assessed post connection of the second North-South interconnector and should be informed by experience of operating the system with low inertia floor levels.



EirGrid SONI

System Strength - The Need for a New Approach, Policy and Metrics

A need for a streamlined, holistic approach to assessing system strength on the network in the planning and operations timeframes has been identified. To this end, EirGrid and SONI are actively developing a system strength policy that defines key parameters and methodologies. The policy will enhance the capability to assess system strength at planning stage and in real-time operations in EirGrid and SONI.

Operational constraints can be used to target areas with system strength scarcities, providing signals for investment in infrastructure, new generation resources and the procurement of system services.

System Strength Today

The relative strength of the network is being tested in many areas. System strength is monitored, and risk assessed in different ways using different tools in system operations.

- The dynamic stability assessment tool monitors transient, voltage and frequency stability in real time with look ahead capability.
- Limited short circuit level monitoring for EirGrid in the EMS.[1]
- Small-signal stability and frequency oscillations are also monitored in the EirGrid and SONI Wide Area Monitoring System (WAMS) using Phasor Measurement Units (PMUs).

Key Drivers

Key drivers for a new approach to System Strength:

- Decommissioning/scheduling reduction of (conventional) synchronous generators;
- To maintain stable operation of IBRs during high SNSP scenarios;
- To manage unwanted interactions between HVDC interconnectors and large offshore wind farms connecting in close proximity;
- Voltage management in Dublin and dynamic stability concerns in South Ireland during high SNSP scenarios;
- Small-signal stability challenges and power quality considerations; and
- Network protection adequacy.

Progress Till Today:

2024

EMT Roadmap (key enabler)

Future of System Strength Project

Initial Industry Outreach

2025

Development and Rollout of Policy

2026

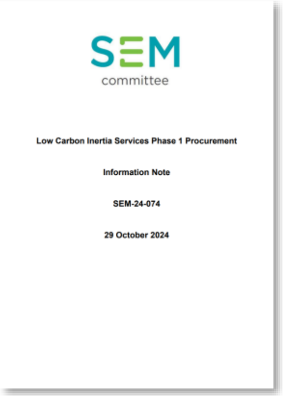
Development of Metrics

[1] Currently not at SONI, where this could potentially be incorporated in the Operational Tools & Capability Enhancement (OTCE) programme.

Dynamic Stability - Updates 2022-2024

Overview of updates to dynamic stability since the initial release of the first Operational Policy Roadmap version in 2022.

Inertia	• Maintained the **23 GVA.s All-Island inertia floor**, due to changing system needs. • Introduced **4 GVA.s of low-carbon synchronous condensers**. • **Procured LCIS Phase 1 around 11 GVA.s** to be connected north and south by 2027. • Exploring grid-forming capability on upcoming HVDC Interconnectors. • Started assessment of required FRT policy and grid code changes for large energy users and DERs.
System Strength	• Delivered the '**Future of System Strength**' project in 2024. • Delivered the **Roadmap for EMT** Implementation. • **Engaged and consulted industry** around system strength. • Currently developing the first system strength policy. • Currently developing grid-forming strategy. • Currently implementing EMT modelling capabilities
RoCoF	• Formalised the **1 Hz/s All-Island RoCoF** operational policy. • Continuously monitored RoCoF post major contingencies – with no violations detected.
SNSP	• In early 2025 a trial to increase the SNSP **limit 80%**, will be initiated, while maintaining other dynamic stability constraints.
MUON	• **Reduced the minimum units in Ireland to 4 from 5 (7 All-Island).** • SONI are considering a trial for a reduction to 2 units in Northern Ireland for certain operational scenarios currently under specific operational scenarios.


SEM committee

Low Carbon Inertia Services Phase 1 Procurement

Information Note

SEM-24-074

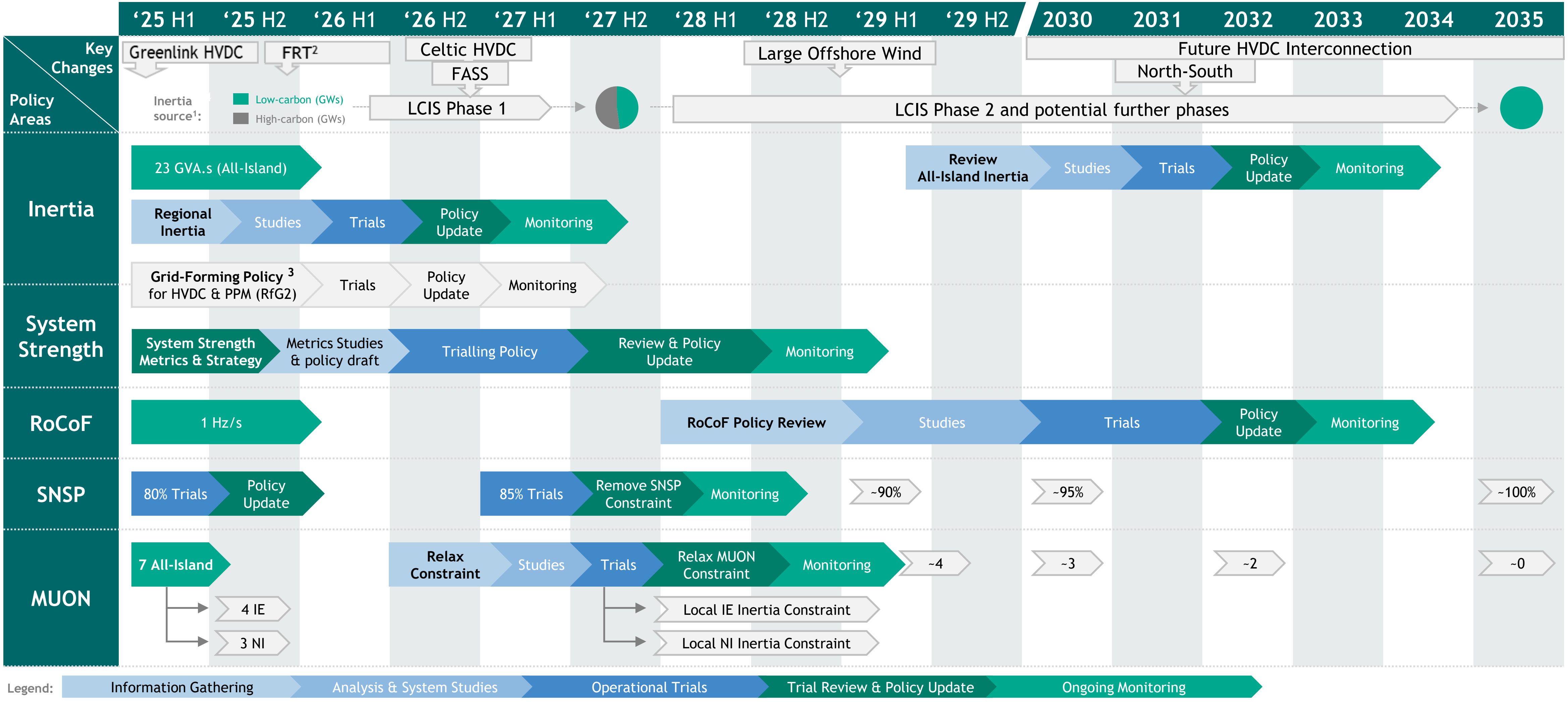
29 October 2024

SEM LCIS Phase 1 procurement report (link).

Stakeholder Engagement session to introduce System Strength requirements for secure system operation (link).

EirGrid SONI

Dynamic Stability - Milestones & Timeline 2025-2035*



[1] Indicative values.
[2] Grid Code requirements for Fault-Ride Through capability of Demand Facilities in place.
[3] Indicative timeline for information purposes only, there is a dependency with the ENTSO-E RfG and HVDC 2.0 and associated Grid Code changes.
* The timelines and assumptions outlined in this roadmap take precedence over those found in SOEF V 1.1).

EirGrid SONI

Dynamic Stability – Actions 2025-2035

Overview of actions regarding dynamic stability going forward from 2025 through 2035.

Inertia	• **2025-2027**: Maintain the All-Island 23 GWs inertia floor. • **2025-2026**: Initiate procurement of LCIS Phase 2. • **2025-2026**: Investigate and introduce a policy for the use of GFM in operations in line with a) HVDC capability and b) PPMs/IBRs requirements, contingent on the TSO/DSO agreed implementation of the EU RfG2.0. • **2025-2026**: Explore the potential for Regional Inertia floors at least at IE/NI regional level, aligned with LCIS. • **2028-2030**: Explore potential needs for changing inertia floor based on system needs.
System Strength	• **2025**: Deliver the system strength policy. • **2026**: Develop metrics for operational system strength and monitoring capability. • **2027+**: Align network reinforcements and solutions with results from regional inertia/system strength studies. • **2025-2028**: Review grid code standards for prioritisation of active and reactive power under fault conditions.
RoCoF	• **2025-2028**: Maintain the 1 Hz/s second limit up to and beyond Celtic interconnector. • **2028+**: Explore future RoCoF policy, and whether the 1 Hz/s limit may need to change.
SNSP	• **2025**: Increase SNSP limit and monitor response. • **2027**: Remove SNSP as an active constraint on the network, provided there are sufficient localised dynamic stability constraints. • **2027+**: Monitor SNSP as a reportable metric.
MUON	• **2026-2027**: Work towards further relaxation of the MUON constraint while maintaining safe and secure All-Island system operation. • **2027**: Remove the MUON constraint and introduction of local security of supply constraints, provided there are sufficient localised dynamic stability constraints.

Dynamic Stability - Stakeholder Impacts

Between 2025 and 2035, EirGrid and SONI foresee the following impacts for stakeholders:

- **Renewable Generators**
  - During the operational trials, renewable (e.g., wind) generation is likely to be less curtailed during periods of high wind and/or low demand.
- **Conventional Generators**
  - Some conventional generator units may be run less frequently during periods of high renewable generation and/or low demand during the operational trials, and if operational policies are changed.
- **System Services Providers**
  - Synchronous condensers and other low-carbon inertia providers will be included as part of the regional inertia model.
  - The system strength policy will be informed by system service provider capability.
- **Large Energy Users**
  - Increased dynamic performance monitoring.
  - As required, define new standards and requirements to ensure that system security is maintained (i.e., on fault ride through performance).
- **Distribution System Operators (DSOs)**
  - Impact will be considered under the respective TSO-DSO (SONI-NIEN and EirGrid-ESBN) joint programmes of work.

5. Reserves and Ramping

Reserves and Ramping - Key Objectives

Between 2025 and 2035, EirGrid and SONI will continue to operate the system securely while also aiming to:

1. **Consolidate on all reserve definitions and volumes, by defining a reference incident for contingency reserves,** including upward and downward reserve, fast frequency response and regulating reserves.
2. **Align with European network code requirements** for reserves with 100% containment coverage for reference incidents.
3. **Deploy new day-ahead reserve auction platform for more competitive procurement of reserves.**
4. Couple to European markets for reserve, post-connection of Celtic HVDC.
5. **Schedule and dispatch non-conventional resources such as inverter-connected RES and BESS for reserve provision** across all tranches.
6. **Refine the ramping margin policy** and RM system service volume requirements.
7. **Increase the All-Island interconnector ramping rates in stages** in line with Greenlink, Celtic and potential new HVDC interconnections and offshore wind.

Reserves and Ramping in Context

Reserves

The **frequency control is the real-time continuous act of balancing the generation and demand.** It is the most important process performed by the control room operators. To ensure the frequency, operational and statutory limits are met, in a cost-efficient manner, frequency response and reserves are essential to cope with the inherent variability of demand, generation and changes in HVDC interconnectors power transfers, and especially for the loss of large infeeds or outfeeds. Depending on the nature of imbalance, the frequency actions could be automatic or ‘manually’ initiated by the operators.

Frequency reserves are critical for the frequency control process across all system states (normal, alert, emergency and restoration) and every effort must be made to maintain adequate levels of reserves and ensure these are replenished as soon as possible. The existing definitions of the frequency reserves categories are aligned with the ENSTO-E SOGL terminology: Frequency Containment Reserves (FCR) include Primary Operating Reserve (POR) and Secondary Operating Reserve (SOR) as defined in the EirGrid and SONI Grid Codes. Frequency Restoration Reserves (FRR) include Tertiary Operating Reserve 1 (TOR1) and Tertiary Operating Reserve 2 (TOR2) as defined in the EirGrid and SONI Grid Codes. Replacement Reserves (RR) are as defined in the EirGrid and SONI Grid Codes.

Ramping

Ramping is the term used for the r**ate of change of active power per unit time**.

The Ramping Margin (RM) is defined as the minimum level of ramping capability available from online or offline generation and demand units. The Ramping Margin was introduced as part of DS3 workstream to enable safe and secure system operation with higher penetration of renewable generation, aiming to assist with the challenges introduced by the inherent wind and PV forecast errors by providing a certain level of dispatchable generation across different timescales.

Apart from dealing with forecasting errors, the Ramping Margin products can help during times when the output of wind farms is deliberately reduced in anticipation of wind turbine cut-outs or high-speed shutdowns to defensively limit the impact on the system.

The interconnector ramping refers to the change in transfers on the HVDC interconnectors. The fast change of active power output across the interconnectors imposes system operation difficulties, if not enough fast acting plant is available to support these exchanges of power with neighbouring systems. HVDC ramping can be split in normal operation, when moving from current operating reference point to the next as part of a planned schedule and emergency operation, when the output is changing in response to a system event in order to assist with balancing needs.

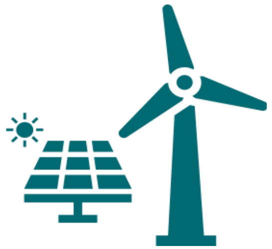
The Need for Reserves and Ramping Operational Policy Changes

This section provides several key reasons for why there is a need for changes in operational policy with regards to reserves and ramping.

1 Definition Consistency and European Alignment

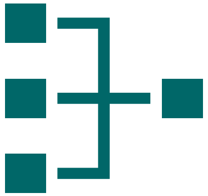
- Ensure alignment with European network code for system operation by having upward and downward reserve volumes and reference incident covered (% of reference incident).
- New day-ahead auction framework for reserves will be introduced in December 2026, with European reserve market coupling post Celtic HVDC. Additional new reserve products may be required further in the future.

2 Proliferation of RES



- Reduction in conventional units on the system reinforces the need to use non-conventional resources for frequency reserves, given their demonstrated capability to provide frequency response.
- Need to utilise BESS, HVDC, DSU for FFR and other reserve services as required.

3 New HVDC and Offshore Wind



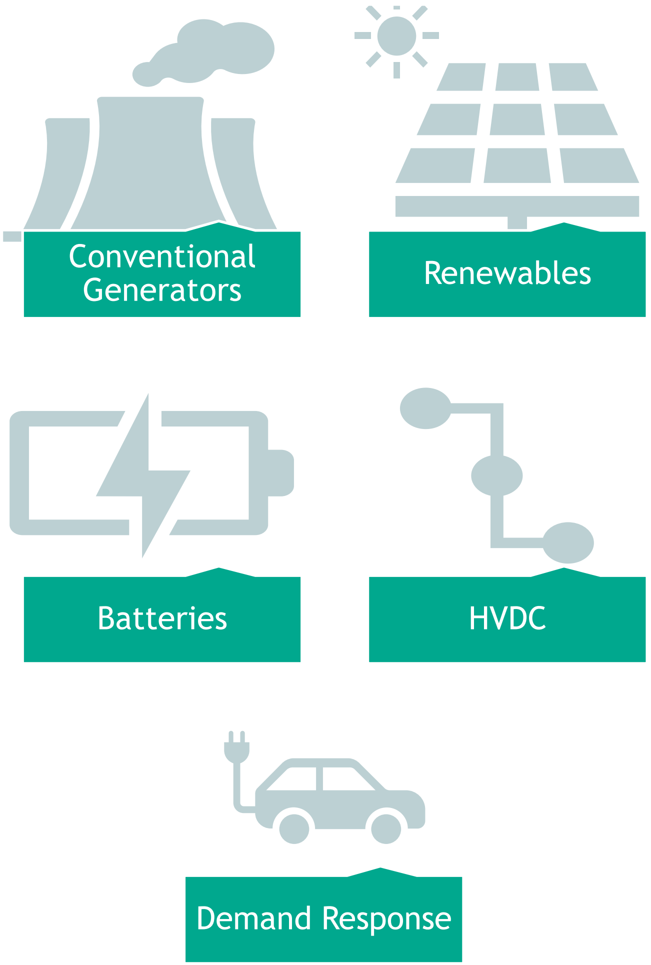
- Two (2) confirmed HVDC interconnectors to Britain and France by 2030 and two potential further connections.
- Six (6) new offshore windfarm clusters on the east coast.
- Requiring rapid ramp rates across all interconnectors to meet market schedules, including that of newly interconnected markets (i.e., France).

Provisions for Frequency Reserves

Traditionally, reserve in all tranches was provided primarily by conventional generation sources, such as gas, coal and pumped-hydro. In the coming decade, **as high-carbon conventional generation is replaced by more low-carbon IBRs, BESS and HVDC, the provision of reserve will have to diversify too.**

- In recent years, **HVDC and batteries today provide fast frequency response**, arresting the frequency deviation in the seconds after a disturbance.
- Although non-synchronous resources are not yet providing inertia, non-synchronous resources **provide downward[1] and when curtailed, upward frequency regulation.**
- **Demand response reduction services** have always been a part of reserve strategies, today with the proliferation of DSUs, can provide reserves in all tranches. EirGrid and SONI are developing a platform for reserve auctions, open to all generation and system service providers. This is expected to go live in December 2026.

In advance of this, studies and operational trials will be carried out on the full range of technologies that can provide reserve, and on the **quality of reserve capacity these technologies can provide**, in line with a new reserve policy document for EirGrid and SONI.



[1] Currently only at EirGrid, SONI is working with industry on an interim solution for downward regulation (requiring trial).

Reserves and Ramping – Updates 2022-2024

Overview of updates to reserves and ramping since the initial release of the first Operational Policy Roadmap version in 2022.

Reserves	• Initiated the **Future Arrangements for System Services (FASS)** program. • Currently developing the **Day Ahead System Services Auction (DASSA)** management platform. • Currently aligning the system services requirements with EU requirements. • Currently defining a new '**reference incident**' for contingent events, to replace the previous largest single infeed/outfeed (LSI/LSO) metrics.
Ramping Margin	• Delivered the **ramping margin policy and calculation methodology**. • Delivered the ramping margin tool for online calculations • Introduced new **RM1, 3, and 8 system services** with procurement and scheduling based on ramping margin calculations.
HVDC Ramping	• Increased the **All-Island HVDC ramping rate to 15 MW per minute as part of a trial** before Greenlink HVDC is energised. • Currently developing a pathway to increase the ramp rate of 20 MW per minute for Celtic HVDC.


SEM committee

SINGLE ELECTRICITY MARKET COMMITTEE

Future Arrangements for System Services

DASSA Market Design

Decision Paper

SEM-24-066

16 September 2024

SEM DASSA Market Design Decision Paper (link)


FASS Programme

Day-Ahead System Services Auction (DASSA) Volume Forecasting Methodology Consultation Paper V1.0

October 2024

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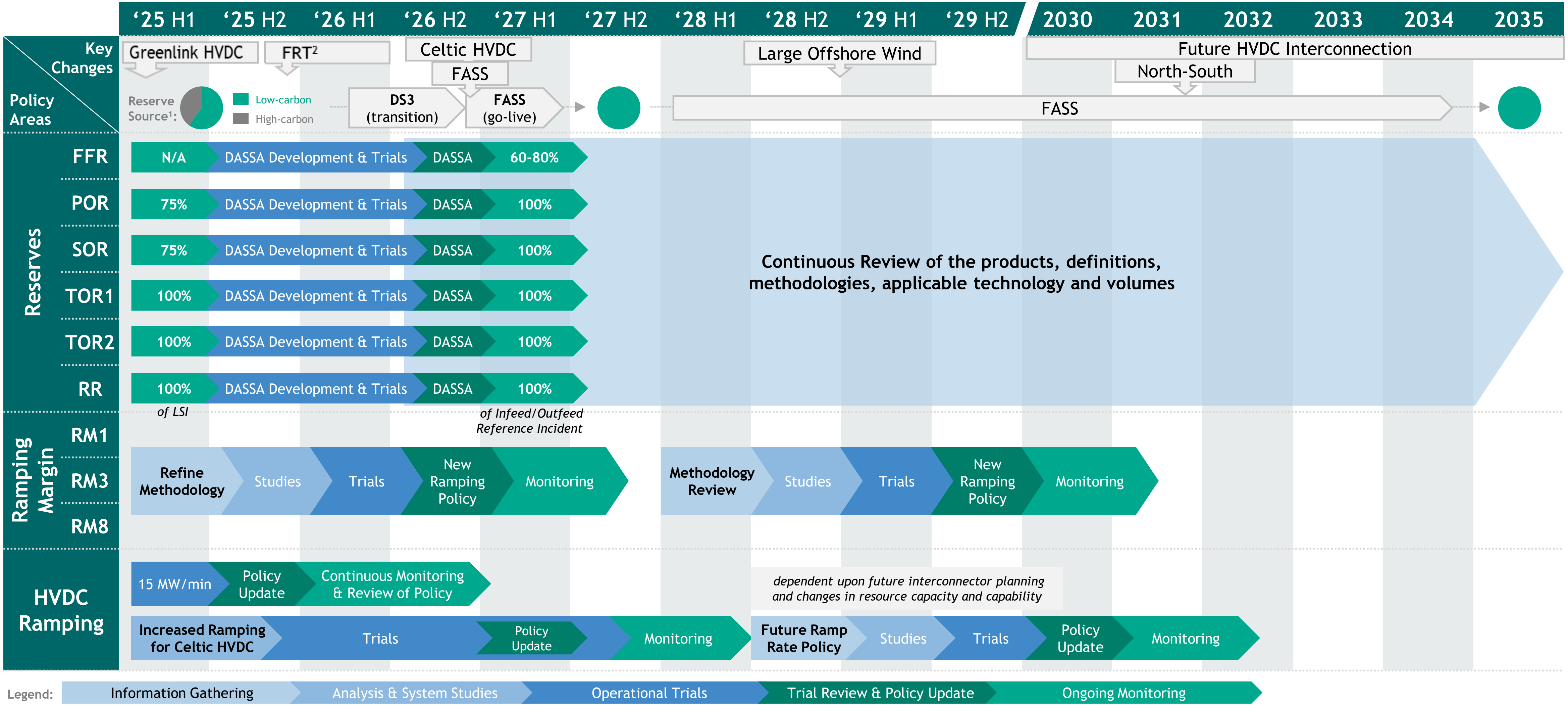
DASSA Volume Forecasting Methodology Consultation Paper (part of FASS Programme). This paper contains an overview of the relation between LSI/LSO, the new reference incident and DASSA on p. 26 (link).

Reserves & Ramping – Milestones & Timeline 2025-2035*



[1] Indicative values. EirGrid and SONI are developing capabilities to enable all reserves to come from low-carbon sources. Ultimately, the market will determine make up of these reserves and facilitating the transition to zero carbon reserves.
[2] Grid Code requirements for Fault-Ride Through capability of Demand Facilities in place.
* The timelines and assumptions outlined in this roadmap take precedence over those found in SOEF V 1.1).

Reserves and Ramping - Actions 2025-2035

Overview of actions regarding reserves and ramping going forward from 2025 through 2035.

Reserves	• **2026**: Finalise and implement the methodology for the new 'reference incident'. • **2026**: Deliver and launch FASS and the accompanying DASSA platform for reserves. • **2026-2035**: Continuous review of the products, definitions, methodologies, applicable technology and volumes.
Ramping Margin	• **2025-2026**: Update ramping margin methodology and policy based on faced operational challenges. • **2025+**: Monitor and assess ramping margin forecast performance requirements over time and update policy as required.
HVDC Ramping	• **2025**: Finalise the All-Island HVDC ramp rate increase to 15 MW/min for the introduction of Greenlink HVDC interconnector. • **2025**: Assess the operational performance of revised ramp rate for Celtic HVDC interconnector to France. • **2025-2027**: Agree and implement revised ramp rate for introduction of Celtic HVDC. • **2027+**: Assess operational performance of further revised ramp rate for potential future HVDC interconnectors to GB and Europe.

Reserves and Ramping - Stakeholder Impacts

Between 2025 and 2035, EirGrid and SONI foresee the following impacts for stakeholders:

- **Renewable Generators**
  - Frequency reserves testing and monitoring.
  - Reserve auction management framework and European market coupling will require more commercial actions and bidding.
- **Conventional Generators**
  - Continued compliance monitoring requirements for reserve provision.
  - Reserve auction management framework and European market coupling will require more commercial actions and bidding.
- **System Services Providers**
  - Compliance monitoring for reserve provision.
  - Reserve auction management framework and European market coupling will require more commercial actions and bidding.
- **Large Energy Users**
  - Future potential opportunity to assist with provision of reserves.
- **Distribution System Operators (DSOs)**
  - Potential opportunity for participation of DER in provision of reserves.
  - Impact will be considered under the respective TSO-DSO (SONI-NIEN and EirGrid-ESBN) joint programmes of work.

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6. Operational Security

Operational Security - Key Objectives

Between 2025 and 2035, EirGrid and SONI will continue to operate the system securely while also aiming to:

1. **Continue actively managing the thermal and voltage transmission constraint groups (TCGs)** that are active in the market and develop plans to remove TCGs post-reinforcement.
2. Develop a framework for **regular assessment and update of thermal and voltage transmission constraints** on the network.
3. Develop a framework for managing operational security using **risk-based approaches (probability and impact) in line with European obligations**.
4. Develop **policies for managing high- and low-fault levels** on the EirGrid and SONI networks.

Operational Security Definitions

Voltage and Reactive Power Management

Voltage ranges are defined in the Section 6 of the **Operating Security Standards (OSS),** the **Transmission System Security and Planning Standards (TSSPS)** and the Grid Code according to the EU **System Operator Guideline (SOGL).**

Higher network voltage levels can increase stability margins and decrease transmission losses, but **the system must be operated within its technical operating envelope**, to reduce the risk of voltage instability or long-term asset damage due to overstressing. Low voltage levels can occur during faults, in high demand, high power transfers, weakly interconnected areas or inadequate generation pattern scenarios. System operators in EirGrid and SONI manage the voltage profile at key network nodes throughout the day, in line with demand patterns.

Short Circuit Level Management

The short-circuit levels are controlled to ensure safety and security. The **short-circuit level must be within the switchgear, equipment and infrastructure rating**, whilst ensuring high enough levels to maintain network protection adequacy, as defined in the grid code and OSS.

Historically, the short-circuit level was used as a proxy to determine system strength when screening for weak areas of the network that may impose operation challenges. In system with high penetration of IBRs this method becomes less adequate.

Thermal Management

The power flows across the network are driven by the requirement for the supply to meet demand. Due to inherent thermal limits associated with the elements of the network the **power flows must be managed to ensure these limits are not violated**, to avoid damage and safety hazards. The power transfers must be controlled during steady state normal operation, but also in response to contingencies.

To ensure all equipment on the transmission system is operated within rated capacity, including short-term admissible overload limits, as specified by the Transmission Asset Owner (TAO), actions must be taken at planning and in the real-time operational stages.

The main actions available to manage the active power flows are the dispatch of generation and HVDC interconnectors, changes in network topology through switching actions, adjusting parameters of power flow control devices like phase-shifting transformers and last resort actions like demand disconnection. Future alternative solutions can involve the utilization of BESS and flexible demand.

The Need for Operational Security Policy Changes

This section provides several key reasons for why there is a need for changes in operational policy with regards to operational security.

1 System Constraints

- Infrastructure development delays and increase in generation connecting remote from the main demand centres, resulting in a constrained network.
- Congestion-imposed difficulties with planned maintenance outages.
- Need for improved network flexibility and control and enhanced system analysis capabilities.

2 Network Reinforcements and Changes

- New HVDC links and new offshore networks expected by 2030 which will require new or updated codes and standards.
- Availability of new network flexibility technologies such as dynamic equipment rating, special protection schemes, power flow controllers, and series compensation.
- Policies and capability to manage smart(er) grid equipment.

3 TSO/DSO Coordination

- Increasing quantity of IBRs located on distribution networks, and the need to ensure visibility on a system level.
- Distribution network constraints driven by IBR export or demand increase due to electrification of heating and transport.
- Need for closer coordination around approach to managing congestion and outages.

General Transmission Constraint Management

Transmission Constraint Management

The **physical network limits on the system impose constraints on the least cost market schedules**. These constraints are reflected in the generation schedule by means of TCGs entered in the market.

The thermal, voltage and dynamic stability constraints are studied by EirGrid and SONI under a range of scenarios, before being entered as TCGs. They are reviewed and updated as required or if major system changes warrant updates. In recent years, EirGrid and SONI have uplifted their operational study capability by utilising improved IBR and demand forecasts in thermal, voltage and dynamic stability studies.

As demand increases and the resource mix on the grid evolves in the coming decade, the pace of change will require a more dynamic approach to transmission constraint management in operations. With the increase in IBR penetration, there will need to be a more frequent and augmented approach to constraint analysis and reporting. SOGL requires members to perform at least yearly review and update of active constraints on their networks.

EirGrid and SONI are transitioning from weekly constraints studies, to yearly, followed by multi-year studies. The aim is to develop the capability to automatically run contingency analysis and determine constraints based on the day-ahead forecasts and schedules and to optimise the market schedule based on near-time analysis results.

Restructuring the process of constraints management will result in improved specificity of constraints, and target signals for network development, resource investment or new system services to alleviate system scarcities. It will require more active system management and study capability.

Example of updated operational constraint set published weekly on the SEM website for the week of 29 Nov 2024 (link).

Short-Circuit Level Management

Both high and low short-circuit levels, also called fault levels, have the potential to introduce operational challenges, generally due to safety considerations in the case of switchgear rating being exceeded or unreliable network protection functions.

High Short-Circuit Levels

Although synchronous machines, traditionally the main source of short-circuit level, are expected to be fewer in number and run less, **fault levels are anticipated to increase with the deployment of more IBR potentially leading to switchgear capability being exceeded.** These situations can be expected under scenarios with high conventional generation running and IBR connected to the network but with very low power outputs.

Low Short-Circuit Levels

Under scenarios with high penetration of IBR and limited synchronous machines, some **traditional network protection functions can be at risk of losing their dependability** due to a reliance on traditional fault levels to ensure safe and normal operation. This poses a risk to safe operation of the grid and needs to be managed carefully to avoid causing serious issues.

Changing Characteristics

Similarly, the **characteristics of the short-circuit current** when the power system is operated with high penetration of IBR can impact protection operation. This can be due to the off-nominal frequencies and high level of harmonic content present in the current injected especially under unbalanced fault conditions from these resources.

Voltage Step-Change

In relatively weak areas of the network, or when the network has multiple simultaneous planned outages, energizing transformers can cause large voltage step changes. These step changes, degrade power quality and can increase system risks and cause impacts on other assets or IBR. Switching or transformer energisation should result in only small step changes within prescribed limits.

To maintain safe and secure performance on the grid in light of these changing short-circuit level behaviours:

1. Operational capabilities must be developed to **accurately analyse short-circuit levels in real-time** using adequate modelling and tooling;
2. Grid code sections may need to be refined to capture negative phase sequence injection from IBRs during faults; and
3. Accurate representation of fault current infeed from IBR must be available to improve confidence in models and allow relaxation of built-in safety margins.

Voltage and Disturbance Management

Due to increasing share of IBRs active on the All-Island system, in many places the system becoming 'weaker' in the traditional system strength sense and other traits provided by traditional synchronous machines. This weakening in system strength can lead to a degradation in power quality and system performance which in turn can impact safe and secure operation of the system. There are **several challenges related to power grid operation associated with this phenomenon**:

1. **Disturbances within the grid are likely to be noticed at greater distances.**
2. **Higher phase unbalance** can adversely affect conventional generation units and their negative phase sequence current protection functions.
3. **Larger voltage step-changes** may become more common in a weaker system. To manage these changes effectively, it may be necessary to adopt special technologies and methods for switching large transformers and static reactive power compensation units. These technologies can help mitigate the impact of sudden voltage changes and maintain stability within the grid.
4. The **depletion of online synchronous machines** further complicates the situation. With fewer synchronous machines dispatched on the grid during high renewable periods, there are fewer sinks available to absorb harmonics, leading to higher levels of harmonic distortion. This increase in harmonic distortion can **elevate the risk of harmonic over-voltages**, posing a threat to the integrity of the grid and the equipment connected to it.

EirGrid and SONI will manage these challenges carefully to ensure safe and secure operation of the grid in light of a changing set of resources connected to the All-Island system.

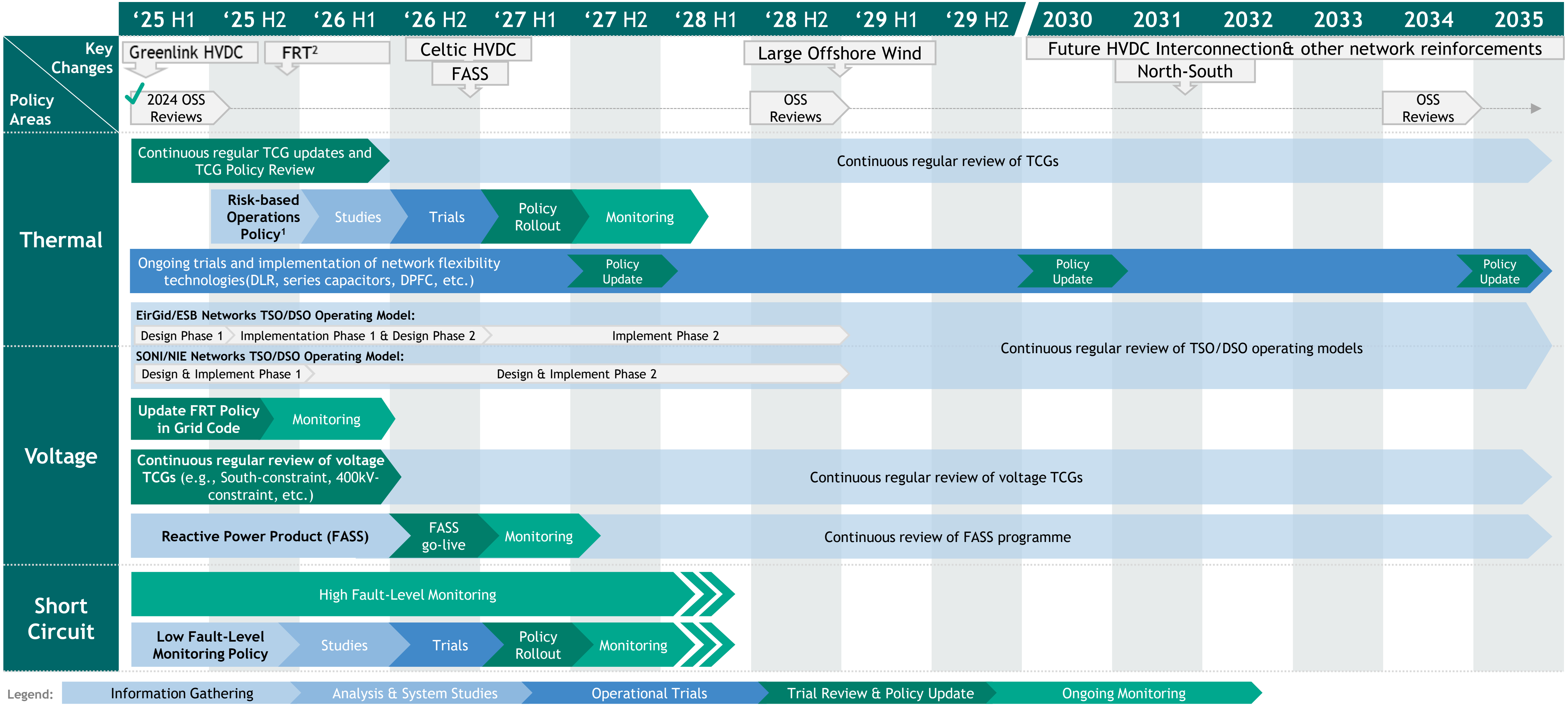
Operational Security - Updates 2022-2024

Overview of updates to operational security since the initial release of the first Operational Policy Roadmap version in 2022.

Thermal	• Delivered a process for **reviewing and updating transmission constraint groups (TCGs)** active in the market upon relevant network reinforcements. • Delivered updated **EirGrid/ESBN TSO/DSO operating model** with initial focus on cross boundary constraints, including annually updated multi-year plan developed together with the DSO, and ongoing work in Northern Ireland on updating SONI/NIEN TSO/DSO operating model. • Conducted a **review of the EirGrid and SONI Operational Security Standards (OSS)** to identify opportunities for relieving constraints while maintaining secure system operation.
Voltage	• Delivered the '**Voltage Trajectory Tool (VTT)**' for live voltage monitoring and forecast application in control room. • Delivered more active voltage TCG management for voltage constraints post-network reinforcements.
Short Circuit	• **Continued improvement and refinement of underlying models** in real time on the EirGrid and SONI systems together with the Transmission Asset Owners (TAOs) ESB Networks and NIE Networks.

EirGrid/ESBN DSO/TSO Multi-Year Plan 2024-2028 (link) and DfE Consultation on Design Considerations for a Smart Systems and Flexibility plan that highlights TSO/DSO interaction for SONI/NIEN (link)

Operational Security - Milestones & Timeline 2025-2035*



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[1] Evolution of the risk-based operations policy, as the current approach is also risk based but not probabilistic.
[2] Grid Code requirements for Fault-Ride Through capability of Demand Facilities in place.
* The timelines and assumptions outlined in this roadmap take precedence over those found in SOEF V 1.1).

Operational Security - Actions 2025-2035

Overview of actions regarding operational security going forward from 2025 through 2035.

Thermal	• **2025+**: Continue active monitoring of the thermal TCG limits, while continuing to develop pathways for eventual removal of these constraints. • **2025-2028**: Develop a process for incorporating risk-based operations in line with EU regulations.
Voltage	• **2025**: Assess ability to relax the South Voltage and 400 kV Voltage TCGs. • **2025-2026**: Develop requirements for voltage ride-through capability for demand facilities and DERs and propagate the required grid code, distribution code and standards changes. • **2025-2026**: Develop support for reactive power / voltage support product as part of FASS. • **2025-2028**: Develop a process for incorporating risk-based operations in line with EU regulations.
Short Circuit	• **2025-2026**: Initiate short circuit monitoring in real-time operations, on the SONI network. • **2025-2027**: Develop a policy on low short circuit levels in weak areas of the network, especially with risks for protection operation, voltage step change and power quality issues.

Operational Security - Stakeholder Impacts

Between 2025 and 2035, EirGrid and SONI foresee the following impacts for stakeholders:

- **Renewable Generators**
  - Introduction of grid code changes related to fault-ride through and other requirements as per the updated (offshore) OSS.
  - Implementation of new network flexibility technologies enabling improvement to localised constraints.
- **Conventional Generators**
  - Conventional generation that was scheduled as a constraint might not be as frequently scheduled with a move to more dynamic transmission constraint group studies.
- **System Services Providers**
  - Voltage and reactive power system services to be developed further.
- **Large Energy Users**
  - Future potential opportunity to assist with congestion and operational security management through provision of flexible demand response services.
  - As required, new standards and requirements will apply to ensure that system security is maintained (e.g., fault ride through performance).
- **Distribution System Operators (DSOs)**
  - Significant engagement and impact with the transmission system operators to agree an operational model.
  - Future potential opportunity for DER to assist with congestion and operational security management. Impact will be considered under the respective TSO-DSO (SONI-NIEN and EirGrid-ESBN) joint programmes of work.

Next Steps

Next Steps

Main next steps following publication of the updated Operational Policy Roadmap 2025-2035.

- ✓ **From Q1 2025, continue existing and initiate new workstreams and actions across the three plans and roadmaps to deliver on the OPR commitments.**

- ✓ **Engage with regulators, stakeholders and the industry more broadly as required, to communicate the OPR plan and actions while emphasising the long-term benefits.**

- ✓ **Review the OPR regularly, with reference to the targets for actions.**

- ✓ **Adjust the plan as required, if risks emerge that impact on deliverability of the OPR.**

- ✓ **Communicate the changes to stakeholders and the rationale behind the changes through regular channels.**

- ✓ **Formally review, update and re-release the OPR in regular cycles, in line with major EirGrid and SONI strategic initiatives or governmental or regulatory target changes.**

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Glossary and Abbreviations

BESS	Battery Energy Storage Systems
DER	Distributed Energy Resource
DLR	Dynamic Line Rating
DPFC	Distributed Power Flow Controllers
DPV	Distributed Photovoltaics
DSO	Distribution System Operator
DSU	Demand Side Unit
EMS	Energy Management System
EMT	Electromagnetic Transient
EWIC	East West Interconnector
FACTS	Flexible AC Transmission System
FCR	Frequency Containment Reserve
FoR	Facilitation of Renewables
FRR	Frequency Restoration Reserve
GFM	Grid-Forming Machine
HVDC	High Voltage Direct Current
IBR	Inverter Based Resource
IE	Ireland
LCIS	Low Carbon Inertia Service
LSI	Largest Single Infeed
LSO	Largest Single Outfeed
MUON	Minimum Conventional Units Online
NI	Northern Ireland
NIEN	Northern Ireland Electricity Networks
OPR	Operational Policy Roadmap
OPRC	Operational Policy Review Committee
OSS	Operating Security Standards
PFC	Power Flow Controller
PMU	Phasor Measurement Unit
POR	Primary Operating Reserve
RoCoF	Rate of Change of Frequency
RR	Replacement Reserve
SEM	Single Electricity Market
SNSP	System Non-Synchronous Penetration
SOEF	Shaping Our Electricity Future
SOGL	System Operation Guidelines
SONI	System Operator of Northern Ireland
SOR	Secondary Operating Reserve
STATCOM	Static Synchronous Compensator
SVC	Static Var Compensator
TAO	Transmission Asset Owner
TCG	Transmission Constraint Group
TOR1	Tertiary Operating Reserve 1
TOR2	Tertiary Operating Reserve 2
TSO	Transmission System Operator
TSSPS	Transmission System Security and Planning Standards
VSC	Voltage Source Converter
VTT	Voltage Trajectory Tool
WAMS	Wide Area Measurement System

Sources

FASS/DASSA	https://cms.eirgrid.ie/sites/default/files/publications/FASS-DASSA-Consultation-Paper-May-2024-EirGrid.pdf
Greenlink HVDC	https://cms.eirgrid.ie/transmission-development-plan-tdp-2024
Celtic HVDC	https://cms.eirgrid.ie/transmission-development-plan-tdp-2024
North-South Interconnector	https://cms.eirgrid.ie/sites/default/files/publications/Network-Delivery-Portfolio-Publication-Q4-2024.pdf
Large Offshore Wind	https://consult.eirgrid.ie/en/consultation/offshore-phase-1-transmission-connection-agreement-asset-sale-and-purchase-agreement
LCIS	https://www.semcommittee.com/news/lcis-procurement-phase-1-information-note


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