

Large Demand Facility Fault Ride- Through Issue and Proposed Solutions

Information Paper prepared by EirGrid and SONI

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Version History

Version	Description	Date Issued
1.0	Issued for stakeholder review.	17 October 2025
2.0	Edits to the document sub-title and the Executive Summary to reflect the change in status of the document from being under stakeholder review to an updated version. Updates to Section 2.4 to reflect more recent stakeholder feedback. Updates to Section 6 reflecting changes to the Grid Code Modification proposal, clarifications and changes to the structure of the modifications. Updates to Section 7 Next Steps.	17 November 2025

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Glossary of terms

Acronym	Meaning
BESS	Battery Energy Storage System
CRU	Commission for Regulation of Utilities
DCC	Demand Connection Code (European Connection Code)
DSO	Distribution System Operator
ENTSO-E	European Network of TSOs for Electricity
FASS	Future Arrangements for System Services
FRT	Fault Ride Through
HVDC	High Voltage Direct Current
Hz	Hertz (unit of frequency)
ITIC	Information Technology Industry Council
kV	Kilo-Volt
LCIS	Low Carbon Inertia Service
LSI / LSO	Largest System Infeed / Largest System Outfeed
MEC	Maximum Export Capacity
MUON	Minimum Number of Units ON
MVA	Mega Volt-Ampere
MW	Mega Watt
OEM	Original Equipment Manufacturer
OSS	Operating Security Standards
PtG	Power to Gas
p.u.	per unit - A scaled ratio of an actual electrical quantity to its base value
RES / RES-E	Renewable Energy Source / Renewable Energy Source of Electricity
RfG	Requirement for Generators (European Network Code)
RoCoF	Rate of Change of Frequency
SC	Synchronous Condenser
SEMC	Single Electricity Market Committee
SNSP	System Non-Synchronous Penetration
SOEF	Shaping Our Electricity Future
SONI	System Operator for Northern Ireland
STATCOM	Static Synchronous Compensator
TSO	Transmission System Operator
UPS	Uninterruptible Power Supply

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1. Executive Summary

EirGrid (Ireland's Transmission System Operator (TSO)) and SONI (Northern Ireland's TSO) are responsible for operating and developing the respective transmission systems of Ireland and Northern Ireland in a secure and coordinated manner, while also strategically planning for long-term electricity needs.

Both TSOs carry out regular modelling and analysis, and present potential solutions to key issues relevant to our work, so that we can continue to ensure the secure and resilient operation of the evolving electricity system.

This Information Paper seeks to provide information on potential solutions to a current challenge in operating the power system, known as "Demand Facility Fault Ride Through", driven by transmission system faults and the resulting collective demand response of most data centres. The paper provides supporting information on the TSOs' proposed Grid Code Fault Ride Through modifications.

Fault Ride Through is a significant and growing challenge to the ability of the TSOs to operate the power system securely. During transient faults on the transmission system, most data centres, even those remote from the fault, automatically reduce their consumption from the grid and switch to their own, temporary, back-up sources of supply. Data centres respond in this way to protect their IT systems and processes, ensuring that the key services they provide to their customers are maintained.

This behaviour has been observed through multiple recorded events on the power system with the aggregated level of demand reduction in each event increasing as data centres continue to ramp up their consumption capacity in line with their connection contracts. In the most recent event of 8 May 2025, a reduction of 387 MW of data centre demand occurred immediately following a remote, transient fault; this represented a 52% reduction in the total demand of data centres at that time.

The impact of these large demand reductions is an imbalance of supply and demand which results in a frequency deviation that is experienced by the whole power system of Ireland and Northern Ireland. Based on the TSOs' detailed power system analysis of credible fault scenarios under current data centre demand levels, such imbalances could be over 1150 MW (a combination of data centre demand reduction and loss of HVDC interconnector export) if no mitigating actions are taken. Such an imbalance would be unprecedented, triggering the activation of high levels of generation tripping defence measures which have the potential to further propagate the impact of the event.

As a result, the TSOs have implemented a number of operational measures to mitigate the immediate risk by taking steps to reduce the potential imbalance, and further urgent action is needed to address the growing challenge. The TSOs, working with industry, wish to ensure that enduring solutions are delivered to accommodate the expected growth in data centre and other new technology loads while maintaining the security of the power system for all consumers¹.

EirGrid recognises the positive and proactive role that the data centre industry has had to previous challenges on the transmission system. During the Security of Supply challenges a number of years ago, the data centre community demonstrated a clear willingness to work with EirGrid to seek solutions to potential capacity issues. As part of this ongoing cooperation and collaboration the data centre community participates in emergency exercises to ensure that all necessary systems and processes are in place should they be called upon.

EirGrid and SONI have engaged extensively with industry over the past number of years on this Fault Ride Through issue and have implemented a number of operational measures to mitigate the immediate risk posed.

¹ EirGrid implements Government policy as directed. The most recent Programme for Government from the Irish Government "Securing Ireland's Future" makes a commitment to support key aspects of the digital economy.

However, further action is now required on the Fault Ride Through challenge and EirGrid and SONI continue to engage with the data centre community to find a solution.

The level of risk will increase further as demand with these fault response characteristics ramps up. Analysis of increased data centre demand scenarios, in line with connection contracts, indicates critical violations of the TSOs' Operating Security Standards (OSS), including significant frequency and Rate of Change of Frequency (RoCoF) deviations, which would lead to more widespread cascade trips of demand and generation. If not mitigated, these scenarios would present a significant and growing risk, exposing all consumers in Ireland and Northern Ireland to the risk of a significant system incident.

The TSOs' response to this issue considers the current operational challenges, immediate actions to support system security and actions to meet the future challenges as data centre demand ramps up. Steps the TSOs are taking to address the issue include:

- Implementation of **Operational Measures** to reduce the magnitude of the potential imbalance and the resulting impact of an imbalance. Measures already implemented include placing limits on HVDC Interconnector exports, as well as enhancement of over-frequency support capability and increased running of a synchronous condenser to provide more reserves and inertia on the power system. These operational measures will continue to be monitored for effectiveness with the implementation of additional measures possible over the short to medium term in response to the TSOs' ongoing assessment of the risks.
- Determining **System Service and Grid Solutions**, such as additional reactive power support, inertia and reserves that would be required to reduce, or respond to, the potential system imbalance; and
- The development of new **Enhanced Capabilities of Demand Facilities**², including 'fault ride-through' standards that would apply to large demand facilities. It is proposed that these requirements are included in the Grid Codes.

Actions in all these areas are required to ensure that the TSOs can operate and develop a secure power system that can facilitate the existing, and growing, capacity of data centres and all large demand facilities into the future.

It is important to note that some of the operational measures above require the TSOs to intervene with electricity market outcomes, e.g. changing dispatch positions of generation and storage or reducing interconnector exports (which typically occur during high renewable output hours). Such actions can increase dispatch balancing costs and ultimately increase costs for consumers. The actions can also result in additional curtailment of renewable generation and increased carbon emissions from replacement thermal generation thus impacting climate action targets. The procurement of additional volumes of system services and/or delivery of new grid infrastructure will additionally increase costs for consumers.

This information paper provides background to the fault ride-through issue, examples of actual system events, power system studies of current and future scenarios, and mitigations/solutions proposed for the currently contracted level of data centre demand. The impact of data centre demand beyond currently contracted levels, and analysis of other technical challenges associated with the integration of new technology loads onto power systems, are subject to further consideration.

This issue is not unique to the island of Ireland. Similar data centre response characteristics have been observed, particularly in North America (e.g. Texas), and there is a growing level of focus among system operators worldwide on addressing this issue. As a small island, Ireland's electricity system has unique characteristics and challenges relative to other larger, more interconnected power systems. Our experts are working with other TSOs internationally to share experience, learnings and solutions.

An earlier version paper was issued to affected customers, government departments and regulators as well as members of the Eirgrid and SONI Grid Code Panels on 17 October 2025. We invited feedback and comment on the information contained in the paper. We also held bilateral meetings with affected

² Demand Facilities is a term used in the EirGrid Grid Code to define all consumers of energy from the electricity transmission system. There is currently no equivalent term currently in the SONI Grid Code.

customers and a webinar on 3 November 2025 to provide an opportunity to engage with TSO experts. Following this webinar we continued with the bilateral meetings. The feedback we received is reflected in this document and where it was possible to adopt these suggestions, we have noted this. In section 2.4 we detail the engagement so far with the Data Centre Industry, their feedback and our responses.

Following feedback, we have provided clarification of the expected behaviour during a fault, updated the proposed grid code modification in respect of the minimum demand recovery level and split the proposed modification into two separate modifications. These updates are set out in section 6.

The TSOs continue to engage and collaborate with industry and will host another webinar (scheduled for 26 November 2025), bi-lateral meetings, and continue engagement through the relevant forums.

We are grateful to industry and their representative bodies for the constructive engagement so far. Their involvement and input is vital. As we work together with industry, government and regulators on this critical issue, our priority remains to ensure system stability, power quality and security of supply for all users of the power system.

2. Background

2.1. Data Centre and New Technology Demand and Power System Demand³

Data centres are a significant and growing component of Ireland's electricity demand (there are no large-scale data centre facilities currently in operation in Northern Ireland). The peak data centre demand to date is approximately 800 MW; approximately 650 MW connected on the transmission system and 150 MW on the distribution system.

In Ireland, there is approximately 2000 MW of demand capacity that is contracted to data centres and other new technology loads at the transmission level, and approximately a further 300 MW contracted at the 110 kV distribution level. As of August 2025; in Northern Ireland there are two data centre connection applications that are deemed effective ⁴, demonstrating an active pipeline seeking to connect. Figure 1 below illustrates the potential growth in data centre and other new technology demand as presented in the All-Island Resource Adequacy Assessment 2025-2034⁵.

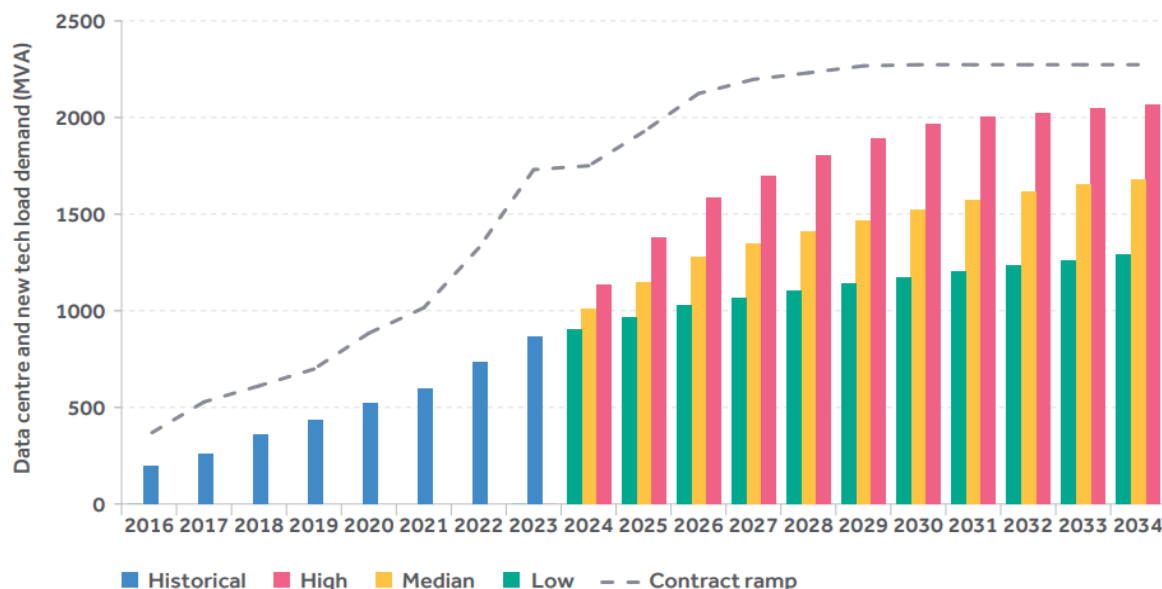


Figure 1 Ireland demand expected from assumed build out of data centres and new technology loads (from All-Island Resource Adequacy Assessment 2025-2034)

Data centres and new technology loads comprised approximately 24% of Ireland's electrical energy requirements in 2024. By 2032, it is expected this will have grown to 30% (median scenario).

The all-island power system, which is operated as one synchronous area, recorded a peak demand of 7502 MW on 8 January 2025, with a minimum demand of 3095 MW (recorded on 9 June 2024). Current data centre demand can therefore make up approximately 11% of peak demand or 26% of minimum demand (currently, data centre demand has a relatively flat profile when compared to the more cyclical total system demand). These proportions of data centre demand relative to total power system demand are important context when considering the overall power system impact of data centre demand reductions.

³ Note that for the purposes of this information paper, Mega-Watt (MW) rather than Mega-Volt-Ampere (MVA) nomenclature is used for simplicity. The MW values referenced may differ slightly from their MVA equivalents which tend to be used in connection agreements and capacity statements.

⁴ [20250819 Connections Register 19 Aug 2025 \(PDF\).pdf](#)

⁵ [All-Island Resource Adequacy Assessment 2025-2034](#)

2.2. Faults

The transmission systems of Ireland and Northern Ireland are constructed and operated to standards for transmission system security and reliability⁶. However, all transmission systems experience faults at times with these most commonly driven by adverse weather events such as lightning and storms.

Faults tend to result in voltage dips (voltages temporarily below normal operating ranges) which can propagate quickly over a wide area. A fault on a transmission line on the Ireland or Northern Ireland transmission systems, particularly on the 400 kV, 275 kV or 220 kV networks, usually results in a voltage dip that can be observed across the entire island. Most transmission system faults are transient in nature with high-speed protection equipment usually clearing faulted equipment within 100 milli-seconds (ms).

Historically, most users of the transmission system (generation sources, interconnectors and demand customers) were able to withstand these transient events and were able to continue generating or consuming once the fault was cleared. Grid Code standards requiring this 'ride-through' capability have been in place for many years for conventional generating units, wind farms, solar farms, batteries and HVDC interconnectors. Standards for demand customers have historically been less stringent as their inherent behaviour, and diversity, has not presented any significant 'ride-through' issue. With the advent of multiple large power electronic-interfaced demand facilities with similar performance characteristics, close electrical proximity and growing demand levels, new challenges have emerged.

Figure 2 below illustrates the difference between how generators typically respond to faults compared to the response of power-electronic interfaced demand facilities (the term UPS - Uninterruptible Power Supply, is used in the illustration). A transmission system fault causes a voltage dip to occur. This voltage dip causes both generation and demand to reduce. Subsequently, the fault is cleared and generation output recovers quickly, however, the reduction in some demand is sustained for a longer period. This difference in generation and demand response results in an imbalance on the power system which results in an increase in system frequency.

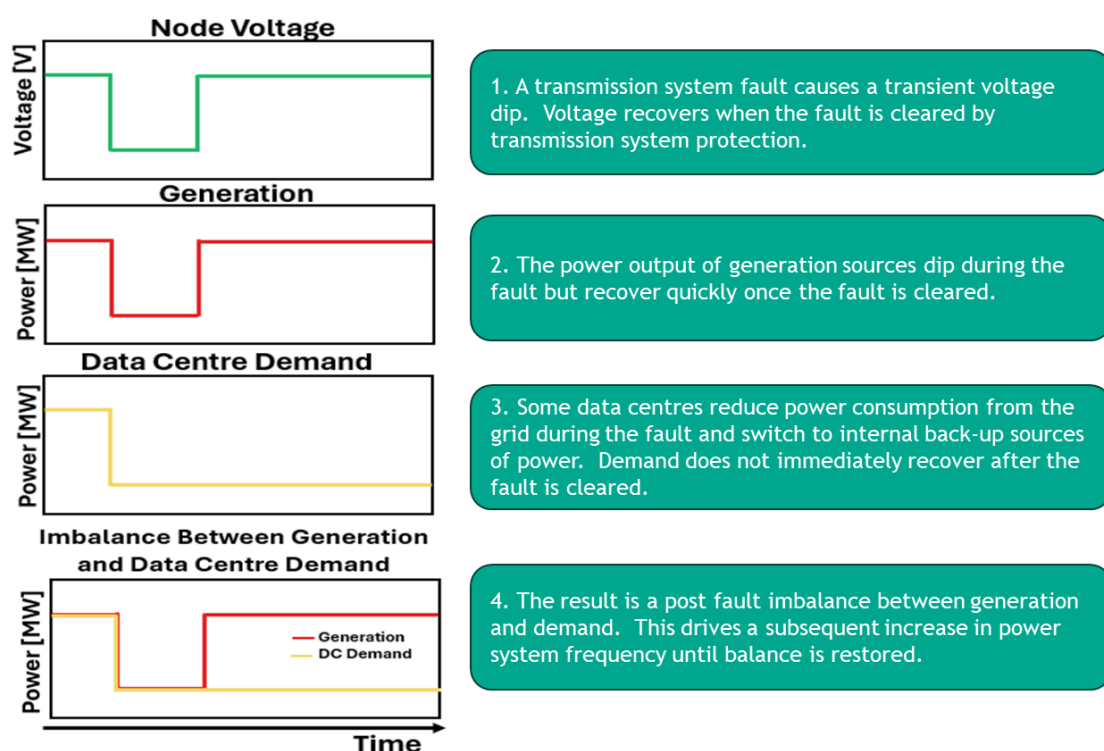


Figure 2 Illustration of Fault Impact on Generation and Data Centre Demand

⁶ [All-Island-Transmission-System-Performance-Report-2024.pdf](#)

2.3. Balancing

The TSOs are required (under Operating Security Standards⁷, European and National requirements^{8,9}) to operate the power system within defined technical limits (frequency range, rate of change of frequency, voltage ranges etc.) to ensure system stability, power quality and security of supply for all users of the power system.

The main issue arising from the demand facility response highlighted in this document relates to frequency quality, both magnitude and rate of change, which are functions of the imbalance between consumption (demand) and generation (supply). When generation and consumption are equal, system balance is achieved, and frequency is stabilized at the nominal level of 50 Hz. Imbalances between consumption and generation causes frequency to rise or drop as illustrated. Maintaining these frequency deviations within defined limits is critical to maintaining the stability of the power system.

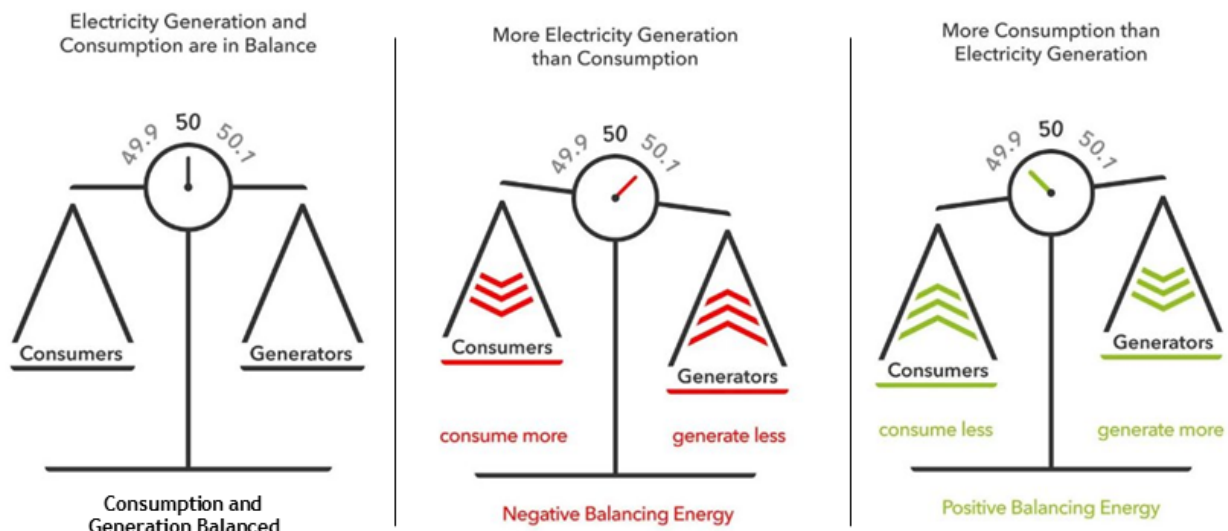


Figure 3 Balance between electricity generation and electricity consumptions

The All-Island power system's relative scale, absence of AC (synchronous) interconnection with other synchronous areas and limited HVDC (non-synchronous) interconnection, presents particular challenges with respect to frequency control which are driven by imbalances between supply and demand of power. Specifically, frequency deviations on the all-island system tend to exhibit both a faster rate of change and a larger magnitude during both normal fluctuations in supply and demand and more significant events such as generator or interconnector trips.

For over a decade, the maximum power system imbalance that could arise on the power system for a credible contingency (loss of a single power system element) has been approximately 500 MW, resulting from a trip (loss) of a HVDC interconnector when operating at full import or export. This potential level of imbalance is challenging to manage on a power system with total demand ranging from approximately 3100 MW to 7500 MW. Significant levels of 'System Services', such as inertia and reserves, are required to ensure that frequency metrics remain within limits and system stability maintained for such events.

The challenge now arising for balancing the power system is that the imbalance caused by the reduction in demand following a fault can be significantly greater than the 500 MW imbalance previously planned for. The following sections set out the observed actual reductions in demand experienced on the power system and the results of power system analysis that consider possible scenarios in which much larger imbalances arise which, unless mitigated, would pose a significant risk to the security of the power system.

⁷ [EirGrid Operating Security Standards](#) [SONI Operating Security Standards](#)

⁸ [System Operation Guideline EU Regulation 2017/1485](#)

⁹ [CRU20078-PR5-Regulatory-Framework-Incentives-and-Reporting.pdf](#);

2.4. Engagement with the Data Centre Industry

EirGrid and SONI have actively engaged with the data centre industry over the past number of years to understand the drivers of the issues from a data centre perspective, to gather individual data centre site data (to inform our models), notify data centres of performance issues observed during fault events and communicate the broader power system challenges arising and need for solutions. This engagement has included a series of task force meetings with data centres held in July and August 2024, and broader industry webinars held in April, October and December 2024.

In addition to these group engagements, the TSOs have held multiple bilateral meetings with individual data centre customers, Original Equipment Manufacturers (OEMs) and developers of newer power supply systems for data centres. These meetings have provided an opportunity for more detailed discussions on specific technical and operational challenges and solutions.

Through these engagements, the data centre industry has provided feedback to the TSOs on earlier versions of the fault ride through proposals. The key points raised by some data centre representatives are set out in the table below along with EirGrid/SONI's response and corresponding references to more detailed consideration of this feedback in this paper.

The TSOs acknowledge the importance of this feedback and remain committed to working collaboratively with data centre and other demand facility customers to develop solutions.

The feedback from these initial engagements and our response is detailed below:

Industry Feedback	EirGrid and SONI Response
Uninterruptible Power Supply (UPS) Capability and Market Availability: Industry representatives expressed concern about the availability of UPS systems that can meet the proposed fault ride-through requirements. They recommended that the TSOs engage with equipment manufacturers to ensure that the proposed standards are technically feasible.	The TSOs acknowledge that there will be challenges for many existing data centre facility designs, including UPS systems, in meeting the proposed fault ride-through requirements. The TSOs have engaged with international equipment manufacturers and we are aware of significant efforts being made to design equipment to meet these requirements and bring solutions to the market. The updated requirements set out in this paper (see section 6) provides further guidance to data centre owners and equipment manufacturers on the standards required.
Retrospective Application and Temporary Derogations: Stakeholders highlighted the challenges of applying new requirements to existing facilities. They requested that temporary derogations be considered, aligned with the operational lifespan of currently installed UPS systems.	The TSOs acknowledge that the application of new Grid Code requirements to existing demand facilities could present compliance challenges. The Ireland and Northern Ireland Grid Codes allow for users to apply for a derogation to a particular Grid Code requirement. Derogation requests are assessed by the relevant TSO with the relevant Regulator ultimately deciding if the derogation

	should be approved or not. These Grid Code derogation processes are set out in section 6.9. The TSOs may also request derogations for classes of users of the grid. Further consideration is being given to the potential approaches to derogations, and their assessment.
Alternative Solutions and System Inertia: Questions were raised regarding other potential solutions being considered by the TSOs, particularly in light of the reduction in conventional generation. The industry sought clarity on how the TSOs plan to maintain adequate levels of system inertia and frequency stability.	The TSOs continue to develop additional System Service / Grid solutions. For example, the TSOs have procured significant volumes of new inertia capability for the power system under the Low Caron Inertia Services (LCIS) initiative with a further procurement round expected to commence in 2026. The TSOs have designed new frequency response services and are implementing the procurement mechanism for these under the Future Arrangements for System Services (FASS) arrangements. These solutions are described in section 5.2. However, it should be noted that the delivery of these additional inertia and reserve capabilities will be insufficient on their own to address the fault ride-through issue. Fault ride-through capability of demand facilities is still required.
Voltage Tolerance Standards: Data centre operators noted that their equipment is designed to comply with the ITIC curve¹⁰, which specifies acceptable voltage tolerance levels. They observed that the TSOs' proposed requirements differ from this standard.	The TSOs' proposed fault ride-through requirements are driven by the characteristics of the power system (the magnitude of the voltage dip resulting from a transmission fault and the speed of response of power system protection). Section 4.2 presents result of analysis if data centre demand does not ride-through transmission faults (based on current protection settings at data centres, as notified to EirGrid by data centre owners, which are reflective of ITIC curve standards). This analysis indicates that significant power system insecurities can result from current performance standards. Section 5.4 presents the results of analysis with data centre demand having the capability to ride-through faults. All non-demand users of the grid (generators, wind farms, solar farms, interconnectors and batteries) are required to meet equivalent fault ride-through requirements in order to ensure stability of the power system. The TSOs' proposed fault ride-through requirements are in line with standards being developed by many other TSOs as set out in Appendix 2.

¹⁰ [ITIC Curve - Voltage Disturbance](#)

Cost Implications and Market Impact: While supporting the goal of grid security, some expressed concern about the financial impact of implementing the new requirements. Specifically, they noted that constraints on UPS design could affect the ability of data centres to enter the Irish market, with potential economic consequences.	The TSOs acknowledge that there will be commercial impacts on data centres. There are also commercial impacts on all electricity consumers as a result of the cost of Operational Measures being implemented (section 5.1) and additional System Service / Grid solutions (section 5.2) that will be required to address this issue.
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The TSOs welcomed the engagement and feedback from demand customers in relation to the earlier version of this paper issued on 17 October 2025, the subsequent multiple bi-lateral meetings and industry webinar on 3 November 2025. This engagement allowed the TSOs to review the input and where possible incorporate changes to the proposed grid code requirements.

Some demand customers indicated that restoring to 95% of pre-fault demand within 500 milliseconds after fault clearance and voltage recovery to 90% of nominal voltage would not be feasible as some loads would not be able to recover this quickly.	Any reduction in the minimum post-fault demand recovery level increases the potential power system imbalance and ability of the power system to recover post fault. However, the TSOs acknowledge that this recovery level is a key concern of some stakeholders given the nature of their loads and therefore we propose to revise the requirement from 95% to 90% recovery within 500 milliseconds after fault clearance and voltage recovery to 90% of nominal voltage. This 90% recovery level also aligns with minimum requirements for other grid users (Power Park Modules and Interconnectors) so ensures consistency of post fault recovery standards across demand and generation sources. This proposed reduction in the minimum demand recovery level may have some impact on the volumes of additional system service /grid mitigations (such as inertia and fast reserves) needed to manage this issue into the future. This impact will be factored into analysis of the additional system service/grid solution requirements.
Some demand customers requested clarification on the proposal that demand facilities “shall remain connected” during voltage dips. The original proposal did not specify how demand facilities should behave during the dip, leading to uncertainty about whether switching to backup systems would be allowed.	The TSOs have clarified (in section 6.6) that “remain connected” means that the customer’s facility must remain electrically connected to the transmission system. During the voltage dip, demand facilities may switch their demand to backup systems (where available), but they should restore 90% of their pre-fault demand within 500 milliseconds after fault clearance and voltage recovery to 90% of nominal voltage.
Feedback was received on the process for application of Demand Connection Code (DCC) standards to non-DCC customers.	The application of DCC requirements to non-DCC facilities will follow processes set out in the DCC in coordination with the regulatory authorities. To enable this, the TSOs now propose to split the proposed modifications into two separate parts.

	Modification 1: incorporating the Rate of Change of Frequency (section 6.5), Voltage Fault Ride Through (section 6.6) and Active Power Consumption Recovery (section 6.7) requirements which are not currently DCC requirements and as such would represent new requirements for all Demand Facilities. Modification 2: incorporating the Frequency and Voltage standards (section 6.4) which require the application of DCC standards to non-DCC facilities. Modification 1 will be progressed initially by the TSOs. Modification 2 will follow the processes as required by the DCC, as appropriate, and in coordination with the requirements of the relevant regulator.
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3. Examples of Observed Response

To illustrate the current demand facility performance issue, the following section presents a selection of real observed responses of data centres during actual system events in Ireland. It is noted that this response is to protect data centre IT systems and processes, ensuring that the key services they provide to their customers are maintained. The Grid Codes do not currently capture requirements for the response of demand facilities during faults that cause the voltage to deviate from normal operational limits.

Table 1 summarises the aggregate level of data centre demand reduction (as recorded across the large transmission and distribution connected data centres) observed for a number of transmission system faults in Ireland.

Date	Transmission System Contingency	Data Centre Demand Reduction	Percentage of Total Data Centre Demand
7 Jan 2022	Limerick: Killonan-Kilpaddoge 220 kV Fault	74 MW	16%
13 Dec 2022	Dublin: Kellystown-Woodland 220 kV Fault	204 MW	34%
26 Jan 2025	Dublin: Poolbeg 220 kV Reactor Fault	321 MW	44%
8 May 2025	Dublin: North Wall - Poolbeg 220 kV Fault	387 MW	52%

Table 1 Data Centre Demand Reduction Summary

The four most recent, and largest, events are presented in further detail in the sections below.

3.1. Killonan-Kilpaddoge 220 kV Fault, 07 January 2022

A fault occurred on the Killonan-Kilpaddoge 220 kV transmission line on 07 January 2022 at 01:50 AM. The single-phase-to-ground fault caused a nearby generator to trip from 171 MW and led to a 74 MW reduction in data centre demand – representing approximately 16% of the total data centre load connected at the time. Although the fault was remote from most data centre locations, the resulting voltage dip propagated across the island triggering the load reduction of data centres in Dublin.

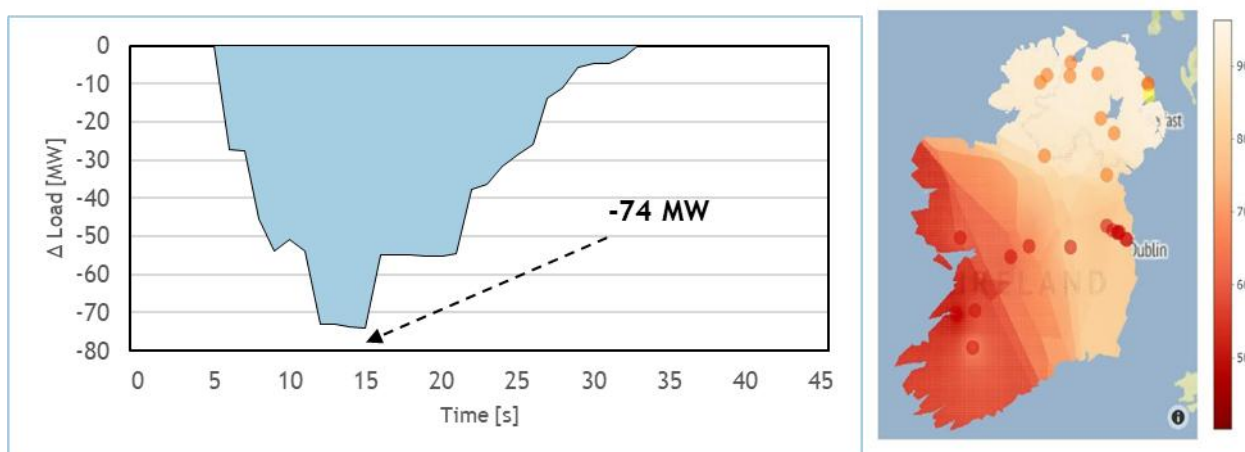


Figure 4 Demand reduction during January 07th, 2022, fault event(left), voltage dip propagation (right)

The plotted dots in Figure 4 represent the location of high-resolution monitoring equipment operated by the TSOs. As the figure shows, the retained voltage in the Dublin was varying between 0.7 and 0.8 per unit.

3.2. Kellystown-Woodland 220 kV line fault, 13 December 2022

A fault occurred on the Kellystown-Woodland 220 kV transmission line on 13 December 2022, at 4:57 PM. A single phase to ground fault caused the line to trip, reclose, and trip again. A significant 204 MW reduction in demand was observed at data centre sites, representing approximately 34% of the total data centre demand at the time of the incident. This sudden decrease in demand caused a rapid change in system frequency, with a Rate of Change of Frequency (RoCoF) reaching 0.12 Hz/s. The system frequency also reached a peak of 50.22 Hz. The following figures show the demand reduction during this event and illustrate the propagation of the voltage dip across the island.

As the figure shows, the voltage dip in the Dublin area was the most severe with the retained voltage varying between 0.3 and 0.5 per unit.

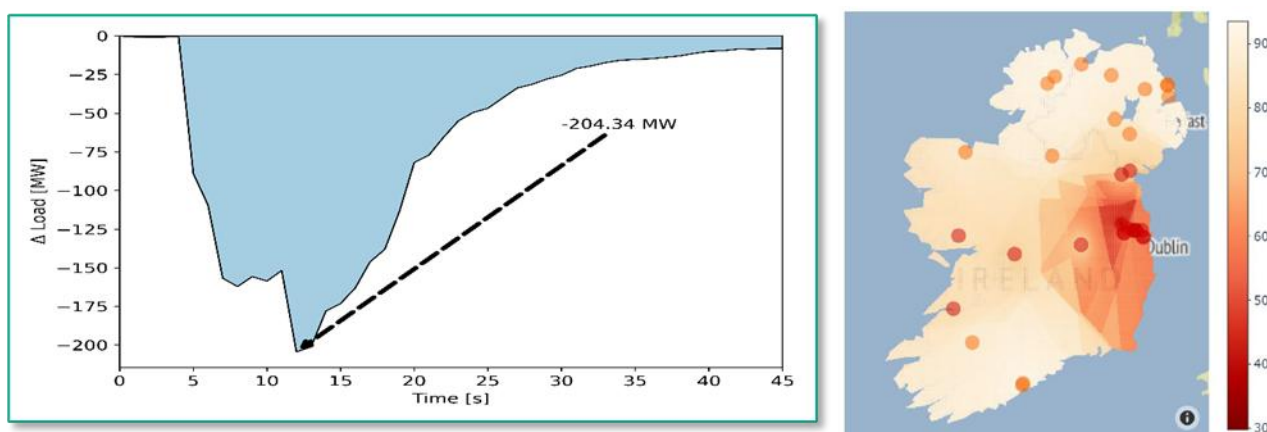


Figure 5 Demand reduction during December 13th, 2022, fault event (left), voltage dip propagation (right)

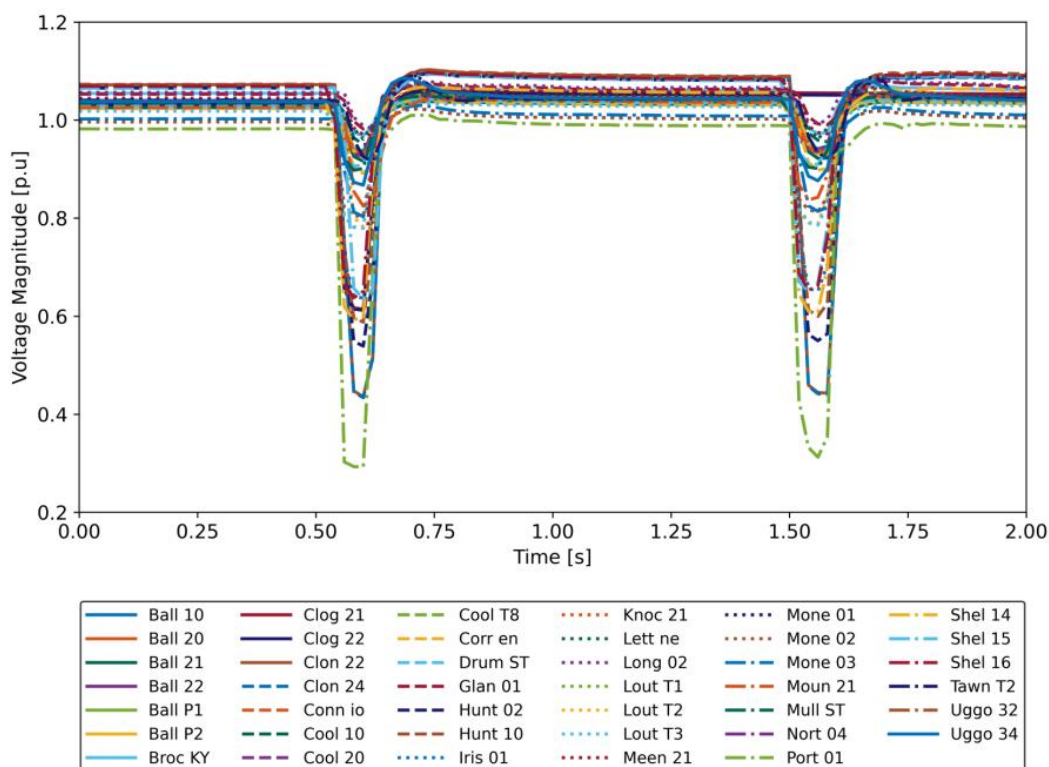


Figure 6 Voltage Magnitude at different locations during the December 13th Fault

Using data from Phasor Measurement Units (PMUs) installed at different locations, the figure above illustrates the voltage magnitude at a selection of nodes on the grid with the most significant voltage dip occurring at Portan station, reaching a low of 0.3 per unit (p.u). The figure below illustrates frequency and Rate of Change of Frequency (RoCoF) values during the same event.

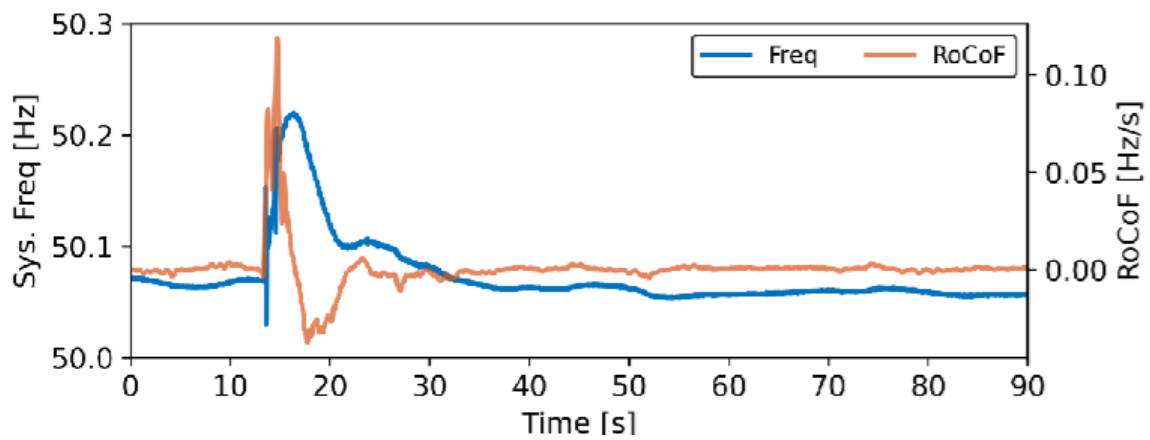


Figure 7 Frequency and Rate of Change of Frequency (RoCoF) during the 13 December 2022 Fault

3.3. Poolbeg 220 kV Reactor Fault, 26 January 2025

On 26 January 2025, a fault on a 220 kV reactor at Poolbeg transmission station caused a widespread voltage disturbance across the power system. This event resulted in a reduction of 321 MW of data centre demand as illustrated in Figure 8. The following figure illustrates the propagation of the voltage dip across the island.

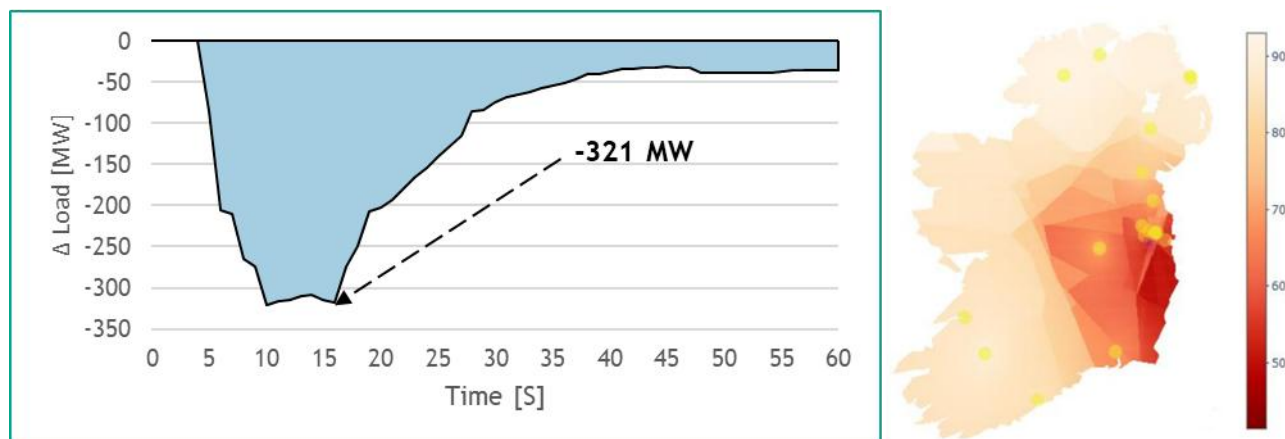


Figure 8 Demand Reduction During Poolbeg Reactor Event 26 January 2025 and Voltage dip propagation (contour map)

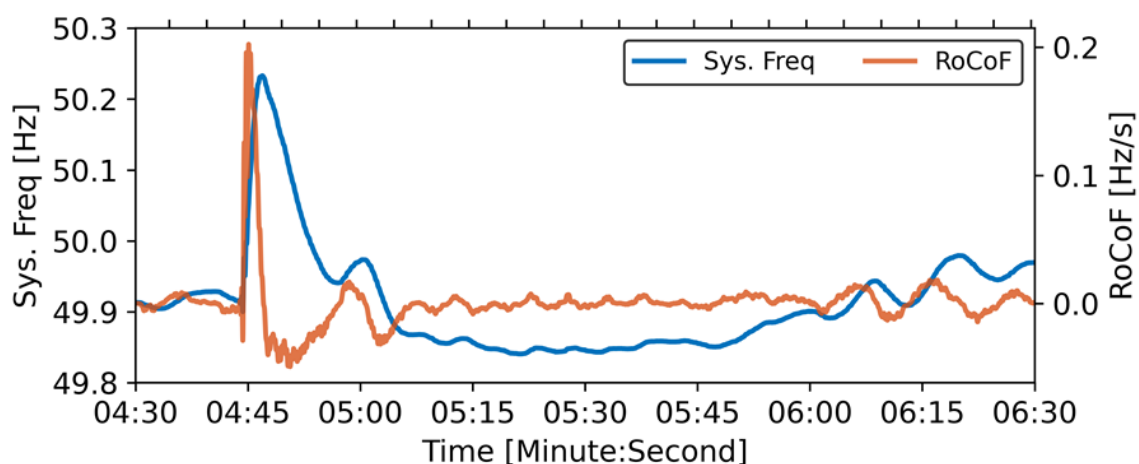


Figure 9 Frequency and Rate of Change of Frequency (RoCoF) during Poolbeg Reactor Event 26 January 2025

3.4. Northwall - Poolbeg 220 kV cable fault, 8 May 2025

On 8 May 2025, a fault on a 220 kV cable in the Dublin area triggered a widespread voltage disturbance across the power system. This incident led to a reduction of 387 MW in data centre demand, the largest demand reduction recorded to date, representing approximately 52% of the total data centre demand at the time of the incident. Figure 10 illustrates both the reduction in data centre demand and the propagation of the voltage dip across the island.

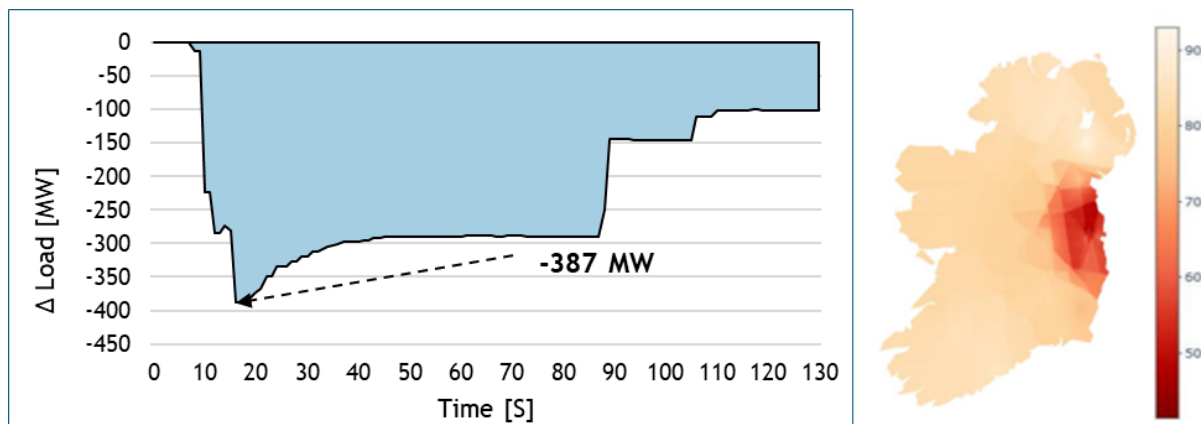


Figure 10 Demand Reduction During cable fault event 08 May 2025 and Voltage dip propagation (contour map)

Figure 11 illustrates the system's frequency response and Rate of Change of Frequency (RoCoF) during the event. Prior to the cable trip, the frequency was stable at 50.02 Hz. The disturbance caused a frequency rise, reaching a zenith of 50.341 Hz, with a RoCoF of approximately 0.26 Hz/s.

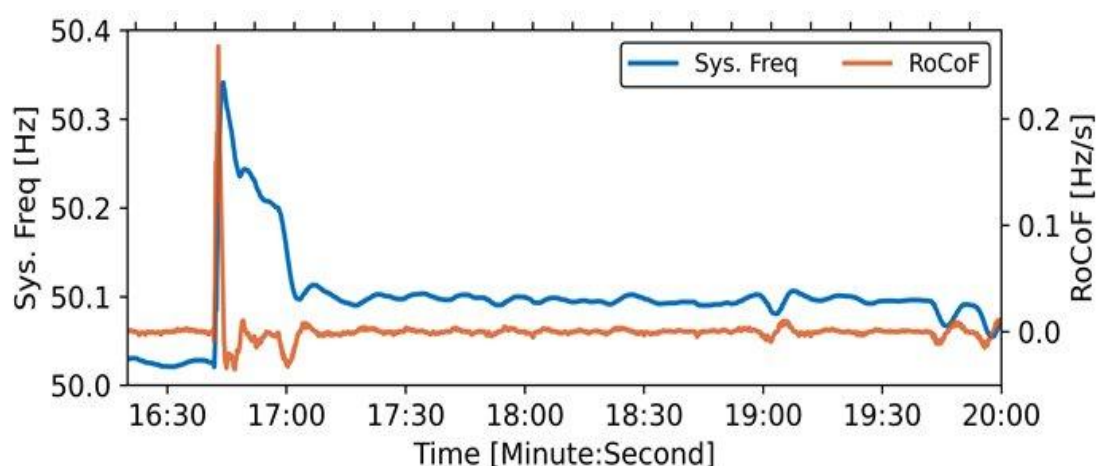


Figure 11 Frequency and Rate of Change of Frequency (RoCoF) during cable tripping Event 08 May 2025

3.5. Summary

The events presented here illustrate the aggregated response of data centres to transmission system faults, with a trend of growing demand reduction reflecting the ramped growth of consumption at these facilities. The individual data centre site data (not presented here for confidentiality reasons) shows that most data centres reduce demand to some extent although there are significant variations between sites and there can be significant variations in individual site response from one fault event to another.

As noted in the introduction to this section, these events represent fault conditions, and voltages outside of normal operating limits, which are currently not captured by requirements for demand facilities in the Grid Codes.

While these specific events did not result in any violation of system limits, they did exacerbate the impact of the initial transmission fault and risked further propagation of the system disturbance. There are scenarios, based on simulations in the TSOs' power system analysis tools (e.g. three-phase rather than single-phase faults that are electrically closer to data centres), in which some faults could trigger much greater levels of demand reduction at data centres which would present much greater challenges to the security of the power system. These scenarios are set out in the next section.

4. Power System Analysis

4.1. Background

As part of standard operational practice, TSOs utilise detailed dynamic models of the power system to simulate fault events and determine their impact to inform system planning and operation processes. These models consider the transmission system, and all large generation and demand sources connected to the transmission system. Some representation of the distribution system and generation and demand sources connected to it, are also modelled. In recent years, the TSOs have developed site specific models for data centre protection schemes based on data collected from their owners. These models are used in power system analysis tools to assess the response of data centre protection to faults, and the impact this has on the overall power system. This analysis capability can be used in both real time operation of the power system to assess system security, and in future scenarios to plan development of the power system.

In assessing the power system impact, two key metrics that the TSOs monitor are frequency and rate of change of frequency (RoCoF) to ensure that they remain within required standards (as specified in European System Operator Guidelines, Grid Codes and Operating Security Standards) for credible contingency events, as specified in the table below. For the purposes of the studies described in this section, the limits applied in our analysis tools were within the standards to account for modelling inaccuracies and to allow for a security margin. The security margins applied in our analysis tools are under review.

Key Metric	Standard	Analysis Tool Limit
Frequency	49.0 Hz to 51.0 Hz	49.2 Hz to 50.8 Hz
Rate of Change of Frequency	+/- 1.0 Hz/s	+/- 0.9 Hz/s

Table 2 Frequency and RoCoF Metrics

These limits are for credible contingencies that the TSOs are required to secure for under operational security criteria. The actual system events presented in the previous section were faults on individual items of transmission equipment (e.g. a transmission circuit or shunt reactor). Through analysis, we have identified more onerous contingencies that could result in more significant levels of data centre demand reduction than have been observed from actual system faults to date. Some single faults can also result in the disconnection of HVDC interconnectors, which, if exporting power at the time of the fault, would add to the system imbalance caused by large demand reduction. While normal imbalances on the power system are managed by activation of reserves, the magnitude of the imbalance in this case can result in activation of automatic special protection schemes that disconnect wind farms.

A potential sequence of events is illustrated in Figure 12. The initial fault, which triggers the disconnection of an interconnector, would be considered a credible contingency. The subsequent reduction in demand at some large demand facilities, and the disconnection of wind farms, would be considered 'consequential losses' which significantly add to the initial event, presenting risks to the stability of the power system. The overall demand reduction (loss of interconnector export plus data centre demand reduction) results in a large imbalance between demand and generation levels.

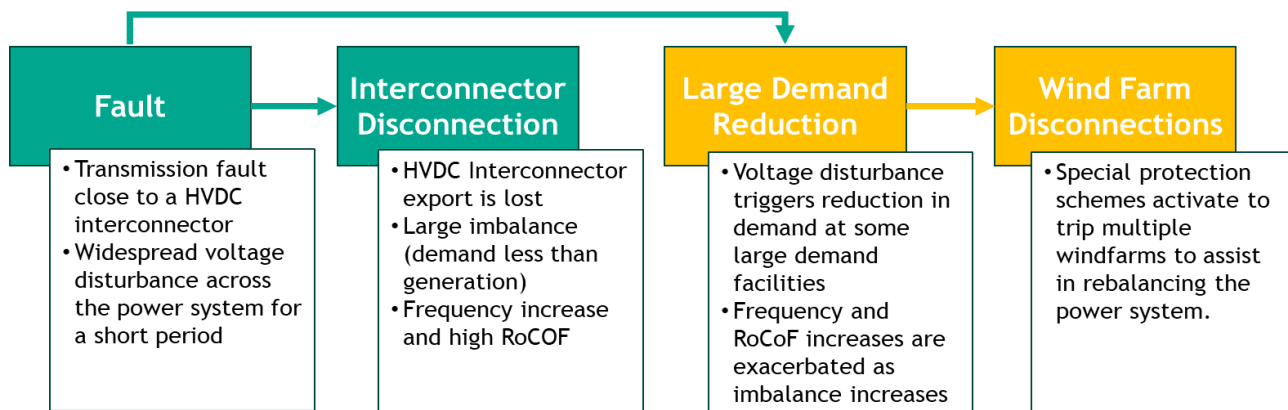


Figure 12 Illustration of a potential sequence of events following a credible contingency

It should be noted that, following the initial fault, all responses are triggered by automated protection systems with the full sequence of events occurring within 1 to 2 seconds.

The sequence outlined above, which includes the disconnection of a HVDC interconnector when exporting, is one of multiple potential contingencies that could trigger a significant reduction in demand at large demand facilities. Other contingencies, not related to HVDC interconnection, and contingencies that are more remote from data centres, could also trigger significant demand reductions given the sensitivity of protection settings of some of these facilities (primarily related to voltage dip sensitivity) and their projected growth in demand.

While the sequence of events set out above, i.e. the initial fault induced reduction in data centre demand, is the primary concern of the TSOs, the automatic restoration of data centre demand after such events (within 1 to 2 minutes) presents additional challenges. As noted above, the initial fault response can trigger the disconnection of significant quantities of generation (which is unlikely to be able to be reconnected to the grid for many hours) to help restore system balance. Data centre demand automatically switching back to grid supply puts additional strain on the power system that could lead to further cascade issues arising. The TSOs are considering additional operating measures that may be needed to address this post fault recovery period.

4.2. Base Case Scenario

The table below summarises the result of dynamic simulation studies performed with increasing levels of data centre demand (up to the 2000 MW which approximates the currently contracted level of data centre demand) and the impact of a credible contingency in proximity to a HVDC interconnector while exporting 500 MW. These study results are considered ‘base case’ as they reflect data centre and power system performance characteristics as modelled in Q1 2025. These results do not reflect the impact of some of the Operational Measures that have subsequently been taken by the TSOs (as set out in section 5.1). Each parameter in the table and the colour coding are also explained below.

DC Demand Considered (MW) / Risk	RoCoF (Hz/s)	Zenith (Hz)	DC demand tripped (A) (MW)	Interconnector export loss (B) (MW)	Overall demand reduction (A+B) (MW)	Wind Generation shed (MW)
600	0.79	50.66	491	500	991	571
800	0.89	50.74	655	500	1155	747
1000	1.09	50.81	829	500	1329	823
1200	1.07	50.90	990	500	1490	939
1500	1.24	51.06	1237	500	1737	1105
2000	1.56	51.10	1586	500	2086	1437

Table 3 Base Case Analysis Results

Each parameter is explained in detail below:

Parameter	Description
DC Demand Considered (MW)	The total level of transmission and distribution connected data centre demand modelled in each scenario. As of the end of 2024, data centre demand was approximately 800 MW. The analysis considered data centre demand up to 2000 MW which approximates the currently contracted data centre demand across transmission and distribution.
RoCoF (Hz/s)	Rate of Change of Frequency calculated during the simulated event. The operational limit is 1.0 Hz/s with an analysis tool limit of 0.9 Hz/s (reflecting modelling and security margins). All the values shown are for positive RoCoFs, i.e. rapid increases in system frequency.
Zenith (Hz)	Maximum system frequency observed in the immediate aftermath of the simulated fault event. The operational limit is 51.0 Hz with an analysis tool limit of 50.8 Hz (reflecting modelling and security margins).
DC Demand Tripped (MW)	Data centre demand reduction as seen by the grid immediately after the simulated fault event.
Interconnector Export Loss (MW)	The HVDC interconnector export quantity that was tripped by the initiating fault event. 500 MW represents the current maximum export capacity and represents the normal maximum export/demand loss managed by the TSOs.
Overall Demand Reduction (MW)	Sum of data centre demand tripped and interconnector export loss.
Wind Generation Shed (MW)	Total wind generation that is automatically disconnected as a result of the high frequency. This is mainly provided by an Over Frequency Generation Shedding scheme (OFGS ¹¹) which is a system defence measure implemented by the TSOs to help arrest very high frequency events and maintain frequency within operational security standards. There are also some individual wind farms tripped by their own internal protection schemes.

Table 4 Description of Results Table Column Headings

The overall results of each of the data centre demand cases are categorised from a system security ‘risk level’ perspective based on the descriptions in the table below.

¹¹ [Over Frequency Generation Shedding Scheme \(OFGS\)](#)

Risk Level	Description
Secure	The power system remains within operational limits using standard operational and market mitigations (e.g. generation re-dispatch and activation of reserves) for credible contingencies.
Secure following reliance on activation of cross-border and/or system defence measures	Reliance on cross-border measures (such as HVDC Interconnector flow restrictions and/or North-South Tie-Line restrictions) and system defence measures (such as over frequency generation shedding) are required to maintain key system metrics (such as RoCoF and frequency) within operational limits. Activation of automatic over frequency generation shedding gives rise to further operational challenges due to the loss of this generation including the voltage and frequency response services provided by these units.
Insecure	Power system is not secure due to violation of system limits for a credible contingency. High risk of major power system failure including the potential for a significant system incident.

Table 5 Description of Risk Level Categories

These results indicate that for data centre demand at Q1 2025 levels (approximately 800 MW) and without further mitigating actions being taken, there is the potential for a very high RoCoF and frequency zenith to occur. Also, the total overall demand reduction (imbalance) can be extremely high resulting in substantial levels of wind generation shedding. Such an event would pose an increased risk to the security of the power system and as a result has necessitated pre-emptive implementation of a number of operational measures to reduce the risk (these operational measures, and their impact, are described in section 5.1). In the 1000 MW of data centre demand scenario, and above, violations of RoCoF and frequency zenith limits arise with overall demand reduction and wind generation shedding increasing further. Violations of these security standards would pose a severe risk to the security of the power system, risking a significant system incident.

The potential sequence of events presents significant risks to the stability of the power system for the following reasons:

- The modern power system has never experienced frequency zeniths like those indicated in the simulations (the maximum frequency experienced from 2015 to date in 2025 is 50.53 Hz). Such high frequencies could trigger other unexpected losses of generation and demand that would further exacerbate the issue.
- The overall magnitude of demand reduction (Interconnector export loss plus demand facility reductions) and the imbalance this creates, would be unprecedented for the scale of the Ireland and Northern Ireland power system.
- The activation of over-frequency generation shedding (currently applied to wind farms by disconnecting them from the grid) is a system defence measure which is not desirable to use for normal credible contingency events. Its activation brings its own risks as the disconnection of large quantities of generation, and the associated services that this generation provides (such as frequency response and reactive power capability) presents challenges to restabilizing the power system post event. The disconnection of generation from the power system in this manner (disconnection at the point of grid connection) also results in them being unavailable to reconnect and generate again for many hours. These risks can be further exacerbated as demand facilities automatically switch their supply back to the grid post event.
- If there was no wind generating at the time of the event there would be no over-frequency generation shedding available from wind. This would present the risk of an even higher frequency/RoCoF event, ultimately tripping of conventional generation which could lead to a significant system incident.

- The RoCoF standard on the power system is ± 1.0 Hz/s reflecting the standard to which power station equipment is designed to withstand and many protection systems on both the transmission and distribution system are designed. Exceeding this limit presents a high risk of further cascade disconnections of generation and demand.

These study results indicate the significant power system challenges faced at existing and currently contracted data centre demand levels if no mitigating actions are taken. Consideration of mitigations and enduring solutions, and analysis performed to illustrate the effectiveness of these solutions, are outlined in the following section.

4.3. Comparison with other power systems

The scale of the potential imbalance on the Ireland and Northern Ireland power system becomes clearer when compared to other synchronous areas. In the Continental Europe synchronous area, the largest single imbalance (also known as the Reference Incident) that is secured for is 3000 MW which accounts for approximately 1 to 2 % of the Continental system demand. In Great Britain, the system operator secures the system against a 1400 MW contingency imbalance (reflecting the loss of a large HVDC Interconnector), which represents approximately 3% to 7% of the GB system demand. The figures are similar for the Nordic synchronous area.

On the All-Island power system of Ireland and Northern Ireland, the normal, planned largest contingency imbalance was 500 MW (representing a contingency on a HVDC interconnector), however, with consequential losses of demand of 655 MW (based on existing data centre demand levels and modelling of their expected response to faults as set out in section 4.2) the total imbalance would be 1155 MW, if not mitigated, representing 17% to 39% of system demand. Increases in data centre demand with similar fault response characteristics would increase these percentages.

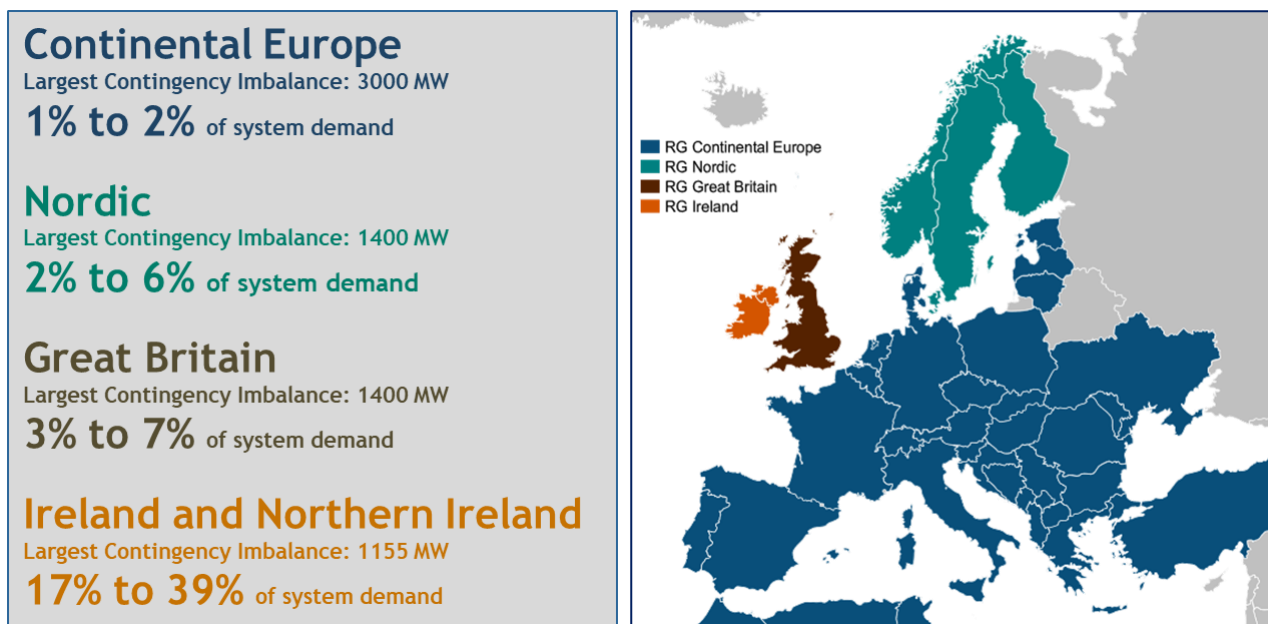


Figure 13 Comparison of size of largest contingency imbalances in different synchronous areas relative to minimum and maximum demand levels

The potential imbalance on the Ireland and Northern Ireland power system, even at existing data centre demand levels, is unprecedented and, unless mitigated, would present a severe risk to the overall stability of the power system. The following section sets out the actions already being taken by the TSOs to manage this issue and proposed further mitigations and solutions.

5. Addressing The Issue

The TSOs' response to this issue considers both the current operational challenges and the future needs of the power system. The TSOs are considering mitigatory measures in both the short term and medium term timeframes and additionally aim to reduce the risk by ensuring enduring improved capability from connected users as illustrated below.

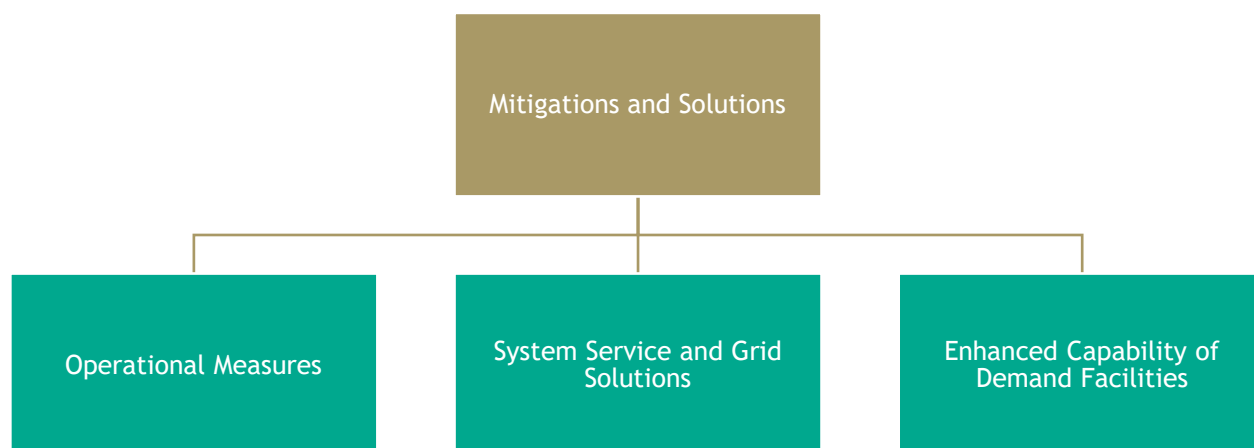


Figure 14 Categorisation of Mitigations and Solutions

The TSOs consider that action in all these areas will be required to ensure the operation and development of a secure power system that is capable of facilitating growth in the capacity of large demand facilities into the future. These mitigations and solutions, including cost implications and allocations, are discussed in more detail in the following sections with further power system analysis presented to illustrate the effectiveness of some of the measures.

5.1. Operational Measures

Operational Measures are actions that can be taken by the TSOs in their role as operators of the transmission system and energy market. They tend to be actions that are taken in operational timeframes that have direct operational and energy market implications for parties connected to the power system such as generators, wind/solar farms, batteries and HVDC Interconnectors. Many of these actions increase the cost of operating the power system as they increase energy and System Services costs. These costs are ultimately paid for by the end electricity consumer. The operational actions can also result in increased curtailment of renewable generation with a corresponding increased dependency on conventional thermal generation leading to higher carbon emissions.

The TSOs have already implemented a number of operational measures in response to the increased risk posed by the demand facility fault ride through issue. These include reducing exports on the East-West HVDC Interconnector (EWIC) and increasing the availability of frequency response and inertia services.

The TSOs are actively monitoring and simulating the response of data centres using our real-time and look-ahead dynamic security assessment tool (LSAT). This security assessment tool flags potential issues and allows the TSOs to take pre-emptive operational actions to reduce risk. The TSOs also have standby defensive measures, in the form of automated disconnection of wind generation, to mitigate the potential impact of an event should it happen. A review of this 'Over Frequency Generation Shedding' scheme is underway in response to the growing demand facility fault ride through issue.

Many of the measures implemented require the TSOs to intervene with electricity market outcomes (e.g. changing dispatch positions of generation or reducing HVDC interconnector flows) or reduce renewable

output, which would necessitate further re-dispatch of conventional units. Such actions would increase dispatch balancing costs and ultimately increase costs for consumers, and at times increase carbon emissions.

In addition to the operational mitigations already taken in response to real-time system conditions, broader consideration of operational policy development has been necessary given the projected growth in data centre demand. In particular, the Operational Policy Review Committee (the TSOs' governing body that oversees operational policies) has determined that the system inertia floor be maintained above what was previously planned, and that our plan to trial an increase in the SNSP limit from 75% to 80% be put on hold pending further consideration of the impact of this issue.

A number of Operational Measures that would directly impact demand facilities are also under consideration. These include the potential for pre-emptive curtailment of demand facilities (that pose a fault ride-through risk) and the development of processes for managing post fault restoration of demand in a more controlled manner.

Further growth within current contracted ramps in data centre demand will increase these operational challenges and risk further evolution of key developments in our Operational Policy Roadmap which are needed to achieve 2030 RES-E targets.

The table below summarises the Operational Measures enacted or under consideration by the TSOs.

Operational Measures				
Mitigation Measure	Entity Responsible	Impacted parties, risks & issues	Cost allocation	Consumer cost allocation mechanism
Enabling Active Power and Frequency Control on all wind and solar farms in Ireland to deliver enhanced frequency response. Status: Active	TSO	Wind and solar farms in Ireland being more frequency responsive.	Potential for increased operating costs for wind and solar	Not applicable
Utilisation of Synchronous Condenser(s) to provide inertia Status: Active	TSO	Increased running of synchronous condenser(s) leading to increased energy (consumption) and System Services costs.	Electricity consumers.	Energy costs managed through the Dispatch Balancing cost mechanism via Imperfections tariff Until FASS arrangements are implemented, System Services costs recovered via annual tariffs (DTUoS and SSS tariffs).
Battery Energy Storage Systems (BESS) management Status: Active	TSO	Management of frequency response settings and operational utilisation (e.g. maintaining charging capability) can impact on BESS market participation.	Electricity consumers.	Dispatch Balancing cost mechanism via Imperfections tariff
HVDC Interconnector Frequency Response Management Status: Active	TSO	HVDC Interconnectors providing additional frequency response. Increased System Services costs.	Electricity consumers.	Until FASS arrangements are implemented, System Services costs recovered via annual tariffs (DTUoS and SSS tariffs).

Restrict Interconnector exports to reduce total level of potential demand loss. Status: Active	TSO	Deviating from market schedules, potentially increasing curtailment of RES. Reduced market efficiency.	Electricity consumers.	Dispatch Balancing cost mechanism via Imperfections tariff
Dispatch of conventional generation to ensure adequate inertia availability and reserve provision Status: Active	TSO	Increase volumes of reserves and inertia levels by increased utilisation of synchronous conventional generation. Increase in emissions and potential increase in curtailment of renewable generation.	Electricity consumers	Dispatch Balancing cost mechanism via Imperfections tariff. Until FASS arrangements are implemented, any associated system services costs recovered via annual tariffs (DTUoS and SSS tariffs)
Review relevant operational limits such as MUON, SNSP and Inertia floor. Status: Active	TSO	Delays or reversals of operational policy related to facilitating RES-E targets will increase RES-E curtailment and maintain reliance on conventional thermal generation. Achieving the respective Governments' RES-E and emissions targets at risk.	Electricity consumers	Dispatch Balancing cost mechanism via Imperfections tariff. Until FASS arrangements are implemented, System Services costs recovered via annual tariffs (DTUoS and SSS tariffs).
Expansion and redesign of Over Frequency Generation Shedding Scheme (OFGS) Status: Under Review	TSO	Forced disconnection of wind farms (and potentially other generation sources) and deviation from market schedules. Need to dispatch conventional generation post OFGS activation. Disconnection of generation sources presents additional risk to system security given the loss of system services that this generation provides (e.g. frequency response and reactive power support). OFGS is intended to be used as a defence measure for extreme events, not for normal contingencies.	Electricity consumers	Dispatch Balancing cost mechanism via Imperfections tariff.
Pre-emptive curtailment of demand facilities Status: Under Review	TSO and Demand Facilities	Demand facility process interruption when instructed to curtail demand by the TSO.	Demand Facilities	Not applicable
Controlled restoration of demand facilities	TSO and Demand Facilities	Implementation of operating protocols to manage restoration of	Costs (if any) associated with	Transmission costs recovered via annual tariffs (TUoS).

Status: Under Review		demand facility load post event in line with power system capabilities. Does not solve initial imbalance. Pro-longed 'off-grid' operation of impacted demand facilities.	restoration of transmission assets borne by Use of System customers. Potential cost for Demand Facilities	
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Table 6 Operational Measures enacted / under review by the TSO

5.2. System Service and Grid Solutions

In addition to the Operational Measures outlined above, the TSOs may require enhanced grid and system service solutions to try to mitigate the risks associated with the loss of large volumes of demand. These measures would be aimed at reducing the voltage dip or managing the system imbalance resultant from the loss of a large volume of demand.

Where the installation of reactive compensation, such as STATCOMS or synchronous condensers (Low Carbon Inertia Services - LCIS), may be able to reduce the voltage dip caused by a fault, this could potentially limit the extent to which data centres reduce their demand from the grid. Analysis is ongoing on the effectiveness of STATCOMS given the very high-speed response and potentially significant volume of reactive power capability required to support voltage during a fault.

Increasing the volume of inertia and fast frequency response available may help to reduce the potential Rate of Change of Frequency (RoCoF) and frequency zenith that may occur as a result of demand facility load reduction. This may necessitate greater system service provision from fast acting and low carbon technologies, for example Synchronous Condensers and Battery Energy Storage Systems (BESS).

The TSOs have already completed a process to procure a large volume of inertia via the Low Carbon Inertia Services (LCIS) procurement that concluded in 2024. This capability is expected to start delivering inertia services during 2027. Preparation for a second phase of LCIS procurement is currently underway with a consultation¹² published by the TSOs in July 2025. Under these proposals, significant additional inertia services are expected to be procured for delivery by approximately 2030. As part of this second phase of LCIS procurement, EirGrid is proposing to implement a procurement 'Qualification System' that would allow further inertia procurement phases to be undertaken as system needs evolve. Consideration of the demand facility fault response issue has, and will continue to be, a significant factor in determining the volumes of inertia required on the power system

Under the Future Arrangements for System Services (FASS) programme, aimed at establishing the new arrangements for the provision of System Services in Ireland and Northern Ireland, the TSOs have developed modified and new reserve services¹³ that will assist in managing high frequency events on the power system. Faster frequency response and downward frequency response services are now defined and methodologies developed to allow for procurement of additional volumes of reserve services linked to 'consequential losses' as may arise when some demand facilities reduce demand in a fault event. Arrangements for the procurement of these new reserve services via a daily auction process are currently

¹² [Low Carbon Inertia Service Procurement Phase 2 - Requirements, Contractual and Procurement Arrangements | EirGrid Consultation Portal](#)

[Low Carbon Inertia Service Procurement - Phase 2 | SONI Consultation Portal](#)

¹³ [2025-April-SOEF-Markets-FASS-Volume-Forecasting-Methodology-Recommendations-Paper.pdf](#)
[2025 April - SOEF Markets - FASS - Volume Forecasting Methodology Recommendations Paper | Soni](#)

under development and expected to go live in 2027. Consideration is also being given to alternative mechanisms to deliver additional frequency response services in advance of the new FASS arrangements.

Enhanced modelling of demand facility response, and extensive power system analysis is required to determine the feasibility, volume and location of the system services required to assist with addressing the existing and projected issues. It should be noted that the magnitude and speed of response required to deal with large potential imbalances presents risks of causing oscillations on the power system. In particular, fast responding power electronic devices, such as Batteries and HVDC Interconnectors, can negatively interact and exacerbate the impact of faults. These risks will need to be considered through detailed studies.

Increased volumes of system services will increase costs for the TSOs which will ultimately increase costs to consumers through the existing DS3 Cost recovery mechanisms (through Demand TUoS¹⁴ in Ireland, and the System Support Tariff in Northern Ireland¹⁵) and the forthcoming All-Island System Services Supplier Charge¹⁶.

¹⁴ [EirGrid Statement of Charges 2023-2024](#)

¹⁵ [SONI TUoS-Statement-of-Charges-2023-24](#)

¹⁶ [All-Island System Services Supplier Charge](#)

System Service and Grid Solutions				
Mitigation measure	Entity responsible	Impacted parties, risks and issues	Cost allocation	Consumer cost allocation mechanism
Additional reactive power capability on the transmission system to support system voltage. Status: LCIS (which will provide reactive power capability) progressing. Further detailed studies underway.	TSO / Competitive procurement	Delivery of additional reactive power capability which could include new infrastructure such as STATCOMS. Investment directly by TSO or potentially through a future competitive procurement. Technical feasibility and effectiveness of solution remains under consideration. New infrastructure, including grid connection, is likely to require a multi-year implementation timeline.	Electricity consumers	Transmission costs recovered via annual tariffs (TUoS). Until FASS arrangements are implemented, any associated system services costs recovered via annual tariffs (DTUoS and SSS tariffs)
Additional inertia and frequency response capability to manage increased levels of imbalance Status: LCIS (which will provide inertia capability) progressing. FASS arrangements developed to support new and enhanced reserve capabilities and increased volumes. Further consideration of mechanisms to obtain additional services underway.	TSO / Competitive procurement	Delivery of additional capability which could include new infrastructure to provide inertia and fast reserves delivered by established or new competitive procurement arrangements. Technical feasibility and effectiveness of solutions remain under consideration. There is a particular risk associated with magnitude and speed of response required to deal with potential imbalances causing oscillations on the power system. This risk will need to be considered through detailed studies. New infrastructure, including grid connection, is likely to require a multi-year implementation timeline.	Electricity consumers	Transmission costs recovered via annual tariffs (TUoS). Until FASS arrangements are implemented, any System Service charges recovered via annual tariffs (DTUoS and SSS tariffs)

Table 7 System Service and Grid Solutions

5.3. Enhanced Capability of Demand Facilities

The TSOs are of the view that demand facilities themselves must be designed and operated to be able to ride-through faults on the power system and are therefore proposing to introduce new Grid Code ‘Fault Ride-Through’ standards. These standards would require all transmission connected demand facilities to be able to ride-through faults on the transmission system, remaining connected and recovering quickly to reduce potential imbalance. These requirements are equivalent to those already applied to other users of the power system (conventional generation, wind, solar, BESS and HVDC interconnectors) in respect of voltage ranges, frequency ranges, RoCoF and Fault Ride-Through capability. Details on these proposals are set out in section 6.

Many other TSOs, and TSO representative bodies, are also seeking to develop equivalent standards. Some examples are presented in Appendix 2.

Enhanced Capability of Demand Facilities				
Mitigation measure	Entity responsible	Impacted parties, risks and issues	Cost allocation	Consumer cost allocation mechanism
Fault Ride Through requirements for Demand Facilities Status: Requirements proposed by the TSOs	Demand Facilities	Demand Facility requirement to deliver technical capability to meet new FRT standards.	Costs borne by Demand Facilities.	Not applicable

Table 8 Enhanced Capability of Demand Facilities

5.4. Further Power System Analysis

The TSOs conducted various sensitivity studies to determine the impact of demand facilities achieving fault ride-through and recovery capability and additional grid / system service solutions to resolve the system security issues highlighted in the ‘base case’ analysis work outlined in Section 4.2.

The following scenarios are presented below:

- demand facilities with fault ride-through capability and a 1 second recovery time.
- demand facilities with fault ride-through capability and a 500 milli-second recovery time.
- demand facilities with fault ride-through capability and a 500 milli-second recovery time and additional fast frequency reserve and inertia services.

The first two scenarios consider data centre demand cases at 600 MW, 800 MW, 1000 MW, 1200 MW, 1500 MW and 2000 MW. The final scenario only considers the 2000 MW data centre demand case. In all cases, the recovery time (1 second, or 500 milliseconds) applies to all data centre demand. Note that this analysis is based on the original proposal for 95% demand recovery after fault clearance and voltage recovery to 90% of nominal voltage.

5.4.1. Demand Facilities with fault ride-through capability and a 1 second recovery time

The table below presents the results when demand facilities restore their demand within 1 second after fault clearance (assuming a linear ramp up of demand once the Transmission System Voltage recovers to 90% of the nominal Voltage). As shown, there is improvement in frequency and RoCoF values when compared to the base case scenarios (the values in square brackets are from the base case scenario in section 4.2). However, RoCoF still exceeds the operational limit in scenarios where Data Centre demand is at 1000 MW and above.

DC Demand Considered (MW) / Risk	RoCoF (Hz/s)	Zenith (Hz)	DC demand tripped (A) (MW)	Interconnector export loss (B) (MW)	Overall demand reduction (A+B) (MW)	Wind Generation shed (MW)
600	0.74 [0.79]	50.52 [50.66]	70 [491]	500	570 [991]	171 [571]
800	0.82 [0.89]	50.57 [50.74]	94 [655]	500	594 [1155]	401 [747]
1000	0.91 [1.09]	50.63 [50.81]	117 [829]	500	617 [1329]	497 [823]
1200	0.94 [1.07]	50.64 [50.90]	140 [990]	500	640 [1490]	538 [939]
1500	1.05 [1.24]	50.71 [51.06]	175 [1237]	500	675 [1737]	768 [1105]
2000	1.33 [1.56]	50.84 [51.10]	241 [1586]	500	741 [2086]	1022 [1437]

Table 9 Data Centre demand scenarios: Effect on RoCoF, Frequency, Wind Generation Loss (1-Second recovery)

5.4.2. Demand Facilities with fault ride-through capability and a 500 milli-second recovery time

The results in the table below illustrate the outcomes with a 500 ms demand restoration after fault clearance (assuming a linear ramp up of demand once the Transmission System Voltage recovers to 90% of the nominal Voltage). These results indicate that the level of Data Centre demand that can be connected while keeping frequency and RoCoF values within operational limits could increase to 1500 MW. However, in the 2000 MW scenario, the RoCoF still exceeds the operational limits. This highlights the necessity for recovery times quicker than 500 ms and/or the addition of further system services, such as inertia and fast reserves, to accommodate higher levels of data centre demand.

DC Demand Considered (MW) / Risk	RoCoF (Hz/s)	Zenith (Hz)	DC demand tripped (A) (MW)	Interconnector export loss (B) (MW)	Overall demand reduction (A+B) (MW)	Wind Generation shed (MW)
600	0.68 [0.79]	50.46 [50.66]	70 [491]	500	570 [991]	31 [571]
800	0.74 [0.89]	50.49 [50.74]	93 [655]	500	593 [1155]	36 [747]
1000	0.80 [1.09]	50.53 [50.81]	116 [829]	500	616 [1329]	219 [823]
1200	0.81 [1.07]	50.53 [50.90]	140 [990]	500	640 [1490]	127 [939]
1500	0.88 [1.24]	50.57 [51.06]	175 [1237]	500	675 [1737]	360 [1105]
2000	1.13 [1.56]	50.72 [51.10]	241 [1586]	500	741 [2086]	674 [1437]

Table 10 Data Centre demand scenarios: Effect on RoCoF, Frequency, Wind Generation Loss (500 ms recovery)

5.4.3. Demand Facilities with fault ride-through capability and a 500 milli-second recovery time and additional reserve and inertia services

The table below provides an example of the impact of additional inertia and fast reserves, for the 2000 MW of data centre demand case, in addition to having data centres return to 95% of their pre-fault demand within 500 milliseconds (assuming a linear ramp up of demand once the Transmission System Voltage recovers to 90% of the nominal Voltage). The results show the necessity of operating with an additional 600 MW of fast reserves to help maintain frequency within operational limits. Additionally, more large providers of inertia (synchronous condensers (SC)) must be added to the system to manage RoCoF. The table below demonstrates the improvement in frequency and RoCoF values by adding 600 MW of fast reserves, plus 1, then 2 large sources of inertia.

Additional Reserves (MW) and Number of Synchronous Condensers (SC) / Risk	RoCoF (Hz/s)	Zenith (Hz)	DC demand tripped (MW)	Wind Generation shed (MW)
600 (95 % DC Recovery) plus 1 SC	0.84 [1.56]	50.50 [51.10]	249 [1586]	76 [1437]
600 (95 % DC Recovery) plus 2 SCs	0.78 [1.56]	50.47 [51.10]	241 [1586]	76 [1437]

Table 11 Analysis Results Showing Impact on RoCoF, Frequency, Demand Tripping and Wind Generation Loss with 500ms Response and Additional Reserve and Inertia Services

5.5. Summary of Power System Analysis Results

A summary of the results of the power system analysis set out in sections 4.2 and 0 is presented in the table below.

Study Scenario	Data Centre Demand Case (MW) / Risk	Key Message
1. Base Case - No additional mitigations	600	At the existing level of data centre demand (approximately 800 MW) the potential level of imbalance is significantly above normal LSI/LSO levels and requires activation of system defence measures to mitigate. Without further significant additional mitigations, the currently contracted level of data centre demand (approximately 2000 MW) would result in power system insecurities
	800	
	1000	
	1200	
	1500	
	2000	
2. Modelling of a 1 sec demand recovery time, no additional Reserves/Inertia	600	Application of fault ride-through capability with a restoration time of 1 second (at all data centres) is insufficient to adequately secure the power system.
	800	
	1000	
	1200	
	1500	
	2000	
3. Modelling of a 500 ms demand recovery time, no additional Reserves/Inertia	600	Application of fault ride-through capability with a restoration time of 500 milli-seconds (at all data centres) significantly improves overall system security. However, System Defence Measures continue to be required and insecurities remain at higher data centre demand levels.
	800	
	1000	
	1200	
	1500	
	2000	
4. Modelling of a 500 ms demand recovery time, with additional Reserves (+600 MW) / Inertia (+ 2 x Synchronous Condensers)	N/A	Significant additional System Services / Grid solutions are needed to accommodate 2000 MW of data centre demand in addition to the implementation of fault-ride through capability. (Note only a 2000 MW data centre demand case was considered in this scenario).
	N/A	
	N/A	
	N/A	
	N/A	
	2000	

Table 12 Summary of the results of the power system analysis

Again, the overall results of each of the data centre demand cases are categorised from a system security ‘risk level’ perspective based on the descriptions in the table below (as also set out in section 4.2).

Risk Level	Description
Secure	The power system remains within operational limits using standard operational and market mitigations (e.g. generation re-dispatch and activation of reserves) for credible contingencies.
Secure following reliance on activation of cross-border and/or system defence measures	Reliance on cross-border measures (such as HVDC Interconnector flow restrictions and/or North-South Tie-Line restrictions) and system defence measures (such as over frequency generation shedding) are required to maintain key system metrics (such as RoCoF and frequency) within operational limits. Activation of automatic over frequency generation shedding gives rise to further operational challenges due to the loss of this generation including the voltage and frequency response services provided by these units.
Insecure	Power system is not secure due to violation of system limits for a credible contingency. High risk of major power system failure including the potential for a significant system incident.

Table 13 Description of Risk Level Categories

The base case scenario illustrates the current and future risks to the security of the power system if no additional mitigating actions are taken.

Scenarios two and three illustrate the importance of demand facilities riding through faults and rapidly restoring their demand to the grid. The findings indicate that demand facilities should return to their pre-fault demand levels quickly, with a maximum recovery time of 500 milliseconds to minimise the energy imbalance on the power system. However, even with this recovery time applied to all demand facilities, risks remain at high data centre demand levels.

Scenario four illustrates the impact of the addition of large quantities of additional reserve and inertia services which can assist in reducing the risk that remains at high data centre demand levels, even if all data centres achieve a 500 milli-second recovery time.

These results have informed the development of the TSOs’ proposals for fault ride through requirements for demand facilities as set out in section 6.

5.6. Further Power System Analysis

The TSOs are conducting further analysis of this issue, focusing on operational mitigations such as frequency response settings for existing batteries and HVDC interconnectors, as well as reviewing over-frequency generation shedding scheme settings and their application. The TSOs are also assessing the impact of additional fast reserves on the power system, considering oscillation risks, and evaluating how new technologies may address the system impacts identified in previous studies.

The analysis reported in this section reflects the original proposal for 95% demand recovery within 500 milliseconds after fault clearance and voltage recovery to 90% of nominal voltage. After industry feedback on this requirement, the TSOs have now proposed a reduction in this demand recovery level from 95% to 90%. This may have some impact on the volumes of additional system service /grid mitigations (such as inertia and fast reserves) needed to manage this issue into the future. This impact will be factored into analysis of the additional system service/grid solution requirements.

The impact of data centre demand beyond currently contracted levels, and analysis of other technical challenges associated with the integration of new technology loads onto power systems, are subject to further consideration.

6. EirGrid and SONI's proposed Grid Code Requirements

6.1. Background

Traditionally, the development of the Grid Codes has revolved around the connection conditions and performance requirements for generators, with less detailed and stringent requirements for demand. With the advent of large power electronic-interfaced loads, power systems worldwide are reviewing their connection conditions and performance requirements for new demand types.

Figure 15 provides an overview of the application (currently active or at an advanced stage of forthcoming implementation) of fault ride through standards for different categories of system user as set out in the EirGrid¹⁷/SONI¹⁸ Grid Codes or the European Network Codes (RfG¹⁹, DCC²⁰, HVDC²¹).

Grid Codes		Network Codes (RfG, DCC, HVDC)
✓	Generators	✓
✓	Power Park Modules (PPMs)	✓
✓	Interconnectors	✓
x	Demand Facilities	x
x	Power to Gas Facilities	✓*
x	Electric Vehicles	✓*

Figure 15 Application of Fault-Ride Through standards for different system user types

*Requirements for P2G and EVs are at an advanced stage of development and are expected to be included in the next versions of the relevant European Network Code.

As set out in Figure 15, Generators, Power Park Modules (PPMs), and Interconnectors have Fault Ride-Through requirements in both the Grid Codes and Network Codes. For Power-to-Gas facilities and Electric Vehicles, ACER has recommended proposals²² for amendments to the Demand Connection Code to include requirements for grid connection for these types of demand. Demand Facilities are the only system users that currently do not have these requirements in either the Grid Codes or Network Codes.

The following sections detail the TSOs' proposed Grid Code modifications required to address the issues highlighted in this information note. These modifications are essential for ensuring reliable operation of the grid with the increasing connection of large demand facilities and their impact on grid stability during and after disturbances. The proposal includes specific technical requirements including Fault Ride Through

¹⁷ <https://cms.eirgrid.ie/sites/default/files/2024-07/GridCodeVersion14.2docx.pdf>

¹⁸ https://cms.soni.ltd.uk/sites/default/files/2024-10/SONI_GridCode_Jun_2024.pdf

¹⁹ <https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32016R0631>

²⁰ <https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32016R1388>

²¹ <https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32016R1447>

²² [ACER Recommendation 03-2023 Annex 2 NC DC clean.pdf](https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32023R0003)

(FRT) requirements, frequency and voltage standards, Rate of Change of Frequency (RoCoF) robustness, and active power consumption recovery.

6.2. Grid Code Modifications Process

The Grid Codes and relevant modification processes that apply in EirGrid and SONI are well established and are governed by the EirGrid Grid Code and [Grid Code Constitution and Rules](#), and the [SONI Grid Code Governance for Modifications](#) and SONI's [Grid Code Constitution](#). A brief overview of the process is provided in graphical format below.

Essentially, for the EirGrid Grid Code, any Grid Code participant (User, DSO, TSO) can suggest a Grid Code Modification, which is then brought to the Grid Code Review Panel (GCRP) for review. The Grid Code Review Panel members have an obligation to review the proposal and through the Chairperson can seek further consideration of the proposal or support the submission of the proposed modification to the Regulator (the Commission for Regulation of Utilities (CRU)). The TSO is obliged to submit the final proposals and its recommendation to the Regulator as a Recommendation paper. If the Regulator's decision is to accept the proposed modification the Grid Code will be modified accordingly.

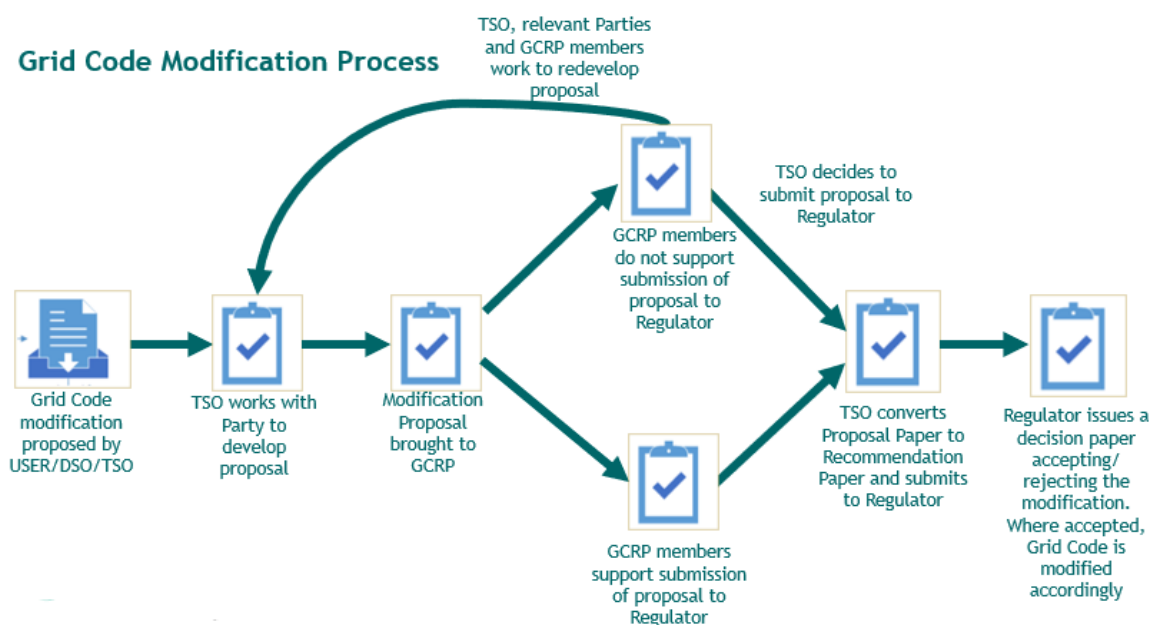


Figure 16 EirGrid Grid Code Modification process overview

For the SONI Grid Code the process is slightly different in that the GCRP can request that modification proposals are withdrawn by the proposer and additionally a consultation must be held before submission of a Grid Code Modification report to the Regulatory Authority (Utility Regulator). A graphical representation of the process is provided below.

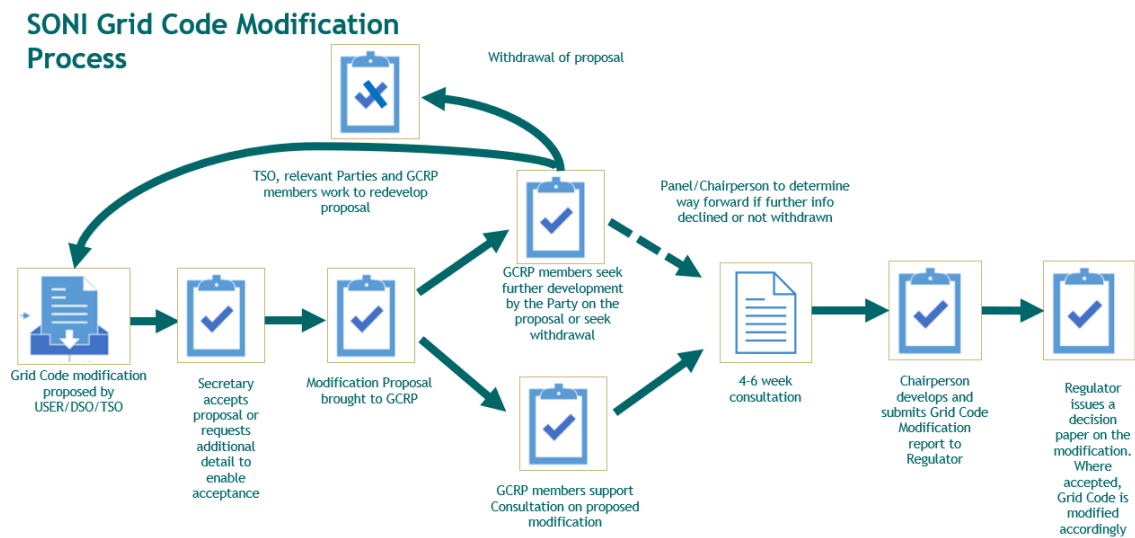


Figure 17 SONI Grid Code Modification process overview

6.3. Scope of Application of Grid Code modification

It is proposed that relevant Grid Code requirements will be applied to all (existing and future) EirGrid connected demand facilities and all future SONI connected Demand Facilities (note that there are currently no large demand facilities connected to the transmission network in Northern Ireland). These requirements will ensure appropriate frequency and voltage standards are applied and that all system users minimise the imposition of risk to system security. These ranges may differ slightly depending on the date of connection of the relevant facility (see below for further information).

As defined in the EirGrid Grid Code, a Demand Facility is “a facility which consumes electrical energy and is connected at one or more Connection Points to the Transmission System. The Distribution System and/or auxiliary supplies of a Generation Unit do not constitute a Demand Facility.”

Demand facilities which connected or contracted to connect (to either transmission or distribution systems) after 7th September 2019 are already obliged to comply with certain technical requirements under the EU Regulation 2016/1388 on Demand Connection Code (DCC). These units are referred to in the Grid Code as DCC units. While there are currently no transmission connected demand users in Northern Ireland, the Utility Regulator in Northern Ireland has recently approved the implementation of the DCC code requirements (see Grid Code modification GC_2023_1²³ and associated Regulatory approval²⁴), which will apply the relevant frequency and voltage standards to all future demand connections (as outlined in Section CC.14.1 of the DCC modified SONI Grid Code).

Non-DCC units are demand units that were connected before the 7th of September 2019 or whose owner has concluded a final and binding contract for the purchase of the main plant on or before the 07 September 2019 and has provided evidence of same, as acknowledged by the TSO, on or before the 07 March 2020.

Additionally, the TSOs propose to raise a modification proposal to include the same RoCoF, Fault Ride Through and Active Power Consumption recovery requirements for all (existing and future) EirGrid and all future SONI connected demand facilities.

²³ <https://cms.soni.ltd.uk//sites/default/files/2025-03/DCC%20Modification.zip>

²⁴ <https://cms.soni.ltd.uk//sites/default/files/2025-03/UR%20Approval%20DCC.pdf>

The TSOs consider that the standardisation of minimum requirements for all demand facilities, rather than technology specific requirements, better future-proof the Grid Codes for other new demand types, such as Power-to-Gas (electrolyser) units.

The TSOs have engaged with the DSOs on this large demand facility fault response issue as some of these facilities are connected to the distribution network in Ireland. The TSOs will work closely with the DSOs to ensure a coordinated response to this issue across both Grid Codes and Distribution Codes.

The following sections set out the Grid Code requirements proposed in relation to:

- Frequency and voltage ranges
- Rate of Change of Frequency (RoCoF)
- Voltage fault ride through (FRT) and
- Active power recovery

These requirements largely reflect existing Grid Code standards that apply to other users of the power system such as generators, windfarms, solar farms, batteries and HVDC interconnectors.

Where appropriate, relevant EirGrid Grid Code clause/section references are used in the following sections, and we have noted where SONI Grid Code section references are yet to be confirmed. For clarity we have outlined as per above, that the DCC standards for voltage and frequency operational ranges will apply to any future connections in Northern Ireland, with new RoCoF, Fault Ride Through and Active Power Consumption recovery requirements to be applied equally to both EirGrid and SONI connected demand facilities.

6.4. Frequency and Voltage Standards

Currently within the EirGrid Grid Code there are requirements for demand facilities connected after the application of the Demand Connection Code (DCC) i.e. for units connected to the network or contracted to connect after 7 September 2019. These standards include those outlined in the latest version of the Grid Code in Section CC.7.4.2.1 regarding frequency operating ranges and time periods, and CC.7.4.2.2 concerning voltage operating ranges.

For demand facilities connected before the application of the Demand Connection Code requirements there are no specific conditions for frequency operating range and required time periods or voltage operating ranges applicable currently. The growth of the demand facility sector and the observed behaviour and risk to system stability as outlined in Chapter 2 & 3 of this report indicates that there is now a need to apply a level of consistency to the performance of such grid connected users to ensure system security.

Therefore, the TSOs seek to introduce the application of relevant standards to all units aiming to ensure that an equitable approach is applied to all grid users e.g. wind farms, solar farms, BESS, conventional generators and demand facilities, enabling all transmission connected users to play a role in ensuring secure power system operation.

Table 14 outlines the existing requirements for EirGrid and SONI connected DCC relevant facilities (and future connections) and the proposed new requirements for non-DCC connected demand facilities in Ireland ²⁵. For clarity, all demand facilities with a connection contract concluded after 7th Sept 2019 have to comply with the DCC requirements. The new requirements, as proposed in Table 14, for remaining operational across defined voltage and frequency ranges by non-DCC units will help bring uniformity to the performance of transmission connected assets. The application of such standards to non-DCC relevant facilities will follow the processes as required by the DCC, as appropriate, and in coordination with the requirements of the relevant regulators.

²⁵ There are no transmission connected demand facilities to date in N.Ireland (either pre DCC or post DCC application)

Note that, as set out in section 6.8, it is proposed that the application of these voltage and frequency requirements are managed through a separate grid code modification to the fault ride-through requirements.

Type	Non-DCC Connected Demand user- (EirGrid connected demand facilities only)	DCC Demand user (SONI and EirGrid connected demand facilities and future connections)																
Requirements for operation at different Voltage ranges	<u>New requirement for non DCC EirGrid New connected facilities</u> <u>EirGrid Grid Code reference: CC7.4</u> Remain synchronised to the Transmission System and operate within the ranges of the Transmission System Voltage at the connection point, for an unlimited time period, as specified below: <table><tr><th>Connection Voltage</th><th>Voltage range (unlimited operation)</th></tr><tr><td>400kV</td><td>0.9 - 1.05 p.u.</td></tr><tr><td>220kV</td><td>0.9 - 1.114 p.u.</td></tr><tr><td>110kV</td><td>0.9 - 1.118 p.u.</td></tr></table>	Connection Voltage	Voltage range (unlimited operation)	400kV	0.9 - 1.05 p.u.	220kV	0.9 - 1.114 p.u.	110kV	0.9 - 1.118 p.u.	<u>EirGrid Grid Code reference: CC7.4</u> Remain synchronised to the Transmission System and operate within the ranges of the Transmission System Voltage at the connection point, for an unlimited time period, as specified below: <table><tr><th>Connection Voltage</th><th>Voltage range (unlimited operation)</th></tr><tr><td>400kV</td><td>0.9 - 1.05 p.u.</td></tr><tr><td>220kV</td><td>0.9 - 1.114 p.u.</td></tr><tr><td>110kV</td><td>0.9 - 1.118 p.u.</td></tr></table>	Connection Voltage	Voltage range (unlimited operation)	400kV	0.9 - 1.05 p.u.	220kV	0.9 - 1.114 p.u.	110kV	0.9 - 1.118 p.u.
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400kV	0.9 - 1.05 p.u.																	
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110kV	0.9 - 1.118 p.u.																	
Connection Voltage	Voltage range (unlimited operation)																	
400kV	0.9 - 1.05 p.u.																	
220kV	0.9 - 1.114 p.u.																	
110kV	0.9 - 1.118 p.u.																	
	<u>No non-DCC large demand facilities currently in Northern Ireland</u>	<u>SONI Grid Code reference CC.14.1.1</u> Remain synchronised to the Transmission System and operate within the ranges of the Transmission System Voltage at the connection point, for an unlimited time period, as specified below: <table><tr><th>Connection Voltage</th><th>Voltage Range (unlimited operation)</th></tr><tr><td>400 kV</td><td>0.9 - 1.05 p.u.</td></tr><tr><td>275 kV</td><td>0.9 - 1.09 p.u.</td></tr><tr><td>110 kV</td><td>0.9 - 1.1 p.u.</td></tr></table>	Connection Voltage	Voltage Range (unlimited operation)	400 kV	0.9 - 1.05 p.u.	275 kV	0.9 - 1.09 p.u.	110 kV	0.9 - 1.1 p.u.								
Connection Voltage	Voltage Range (unlimited operation)																	
400 kV	0.9 - 1.05 p.u.																	
275 kV	0.9 - 1.09 p.u.																	
110 kV	0.9 - 1.1 p.u.																	

Requirements for operation and different Frequency ranges	<u>New requirement for non DCC EirGrid connected facilities</u>	<u>EirGrid Grid Code reference: CC.7.4.2.1 - SONI Grid Code reference: CC14.1.2</u>																												
	Remain synchronised to the Transmission System and operate (without disconnecting) within the frequency ranges and time periods outlined below	Remain synchronised to the Transmission System and operate (without disconnecting) within the frequency ranges and time periods outlined below																												
	<table><tr><th><u>Frequency Range</u></th><th><u>Time Period</u></th></tr><tr><td>47 - 47.5 Hz</td><td>20 seconds</td></tr><tr><td>47.5 - 48.5 Hz</td><td>90 minutes</td></tr><tr><td>48.5 - 49 Hz</td><td>90 minutes</td></tr><tr><td>49 - 51 Hz</td><td>Unlimited</td></tr><tr><td>51 - 51.5 Hz</td><td>90 minutes</td></tr><tr><td>51.5 - 52 Hz</td><td>60 minutes</td></tr></table>	<u>Frequency Range</u>	<u>Time Period</u>	47 - 47.5 Hz	20 seconds	47.5 - 48.5 Hz	90 minutes	48.5 - 49 Hz	90 minutes	49 - 51 Hz	Unlimited	51 - 51.5 Hz	90 minutes	51.5 - 52 Hz	60 minutes	<table><tr><th><u>Frequency Range</u></th><th><u>Time Period</u></th></tr><tr><td>47 - 47.5 Hz</td><td>20 seconds</td></tr><tr><td>47.5 - 48.5 Hz</td><td>90 minutes</td></tr><tr><td>48.5 - 49 Hz</td><td>90 minutes</td></tr><tr><td>49 - 51 Hz</td><td>Unlimited</td></tr><tr><td>51 - 51.5 Hz</td><td>90 minutes</td></tr><tr><td>51.5 - 52 Hz</td><td>60 minutes</td></tr></table>	<u>Frequency Range</u>	<u>Time Period</u>	47 - 47.5 Hz	20 seconds	47.5 - 48.5 Hz	90 minutes	48.5 - 49 Hz	90 minutes	49 - 51 Hz	Unlimited	51 - 51.5 Hz	90 minutes	51.5 - 52 Hz	60 minutes
	<u>Frequency Range</u>	<u>Time Period</u>																												
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49 - 51 Hz	Unlimited																													
51 - 51.5 Hz	90 minutes																													
51.5 - 52 Hz	60 minutes																													

Table 14 Outline of new and existing operational Voltage and Frequency range requirements for Demand facilities

6.5. Rate of Change of Frequency (RoCoF)

Currently there are no requirements for demand facilities to comply with existing RoCoF standards that are applied to generators and other grid users. Given that these standards are critical to ensuring system stability with a changing mix of demand and generation, and the system is now operating to a Rate of Change of Frequency (RoCoF) standard of +/- 1 Hz/s, the TSOs consider that it is important to now require demand facilities to comply with the standard. The TSOs' proposed requirement is for all demand facilities to comply with such standards and ensure uniformity across all system users.

Requirement	All EirGrid and SONI connected Demand facilities
RoCoF requirement	Remain connected to the Transmission System during rate of change of Transmission System Frequency of values up to and including 1Hz per second as measured over a rolling 500 milli-second period. (Voltage dips may cause localised RoCoF values in excess of 1 Hz per second for short periods, and in these cases, the Fault-Ride Through clause CC.7.4.3.2) supersedes this clause (CC.7.4.3.1)) (EirGrid Grid Code reference). Equivalent SONI Grid Code reference; CC.14.1.5)

Table 15 RoCoF Requirement

By applying the RoCoF standards to demand facilities, the grid's overall stability and reliability during disturbances will be significantly improved. For the avoidance of doubt, where voltage dips cause localised RoCoF values in excess of 1 Hz per second for short periods, the Fault-Ride Through requirements outlined below in Voltage Fault Ride Through^{6.6} supersede the RoCoF requirements.

6.6. Voltage Fault Ride Through

Currently fault-ride through requirements are applied to generators and other grid users but not to demand facilities. As evidenced earlier in this report, the lack of such a requirement on demand facilities means that system stability could be compromised.

The TSOs propose that during and following any fault disturbance that results in a voltage deviation remaining on or above the specified voltage-against-time profile at the connection point, demand facilities must remain connected to the transmission system.

‘Remain connected’ means that the customer’s facility must remain electrically connected to the transmission system. During the voltage dip, demand facilities may switch their demand to backup systems (where available), but they should restore their demand to being fed from the grid in line with the requirements set out in section 6.7.

Requirement	All EirGrid and SONI connected Demand facilities
Fault Ride through requirement	Demand Facilities shall remain connected to the Transmission System during and following any Fault Disturbance on the Power System which results in a Voltage deviation which remains on or above the voltage-against-time profile specified in (EirGrid Grid Code Reference Figure CC.7.4.3.2) at the Connection Point.

Table 16 Fault Ride through requirement

This profile, as illustrated in the figure below, outlines the required Voltage against time profile, on or above which the connected demand facility must remain connected to the system.

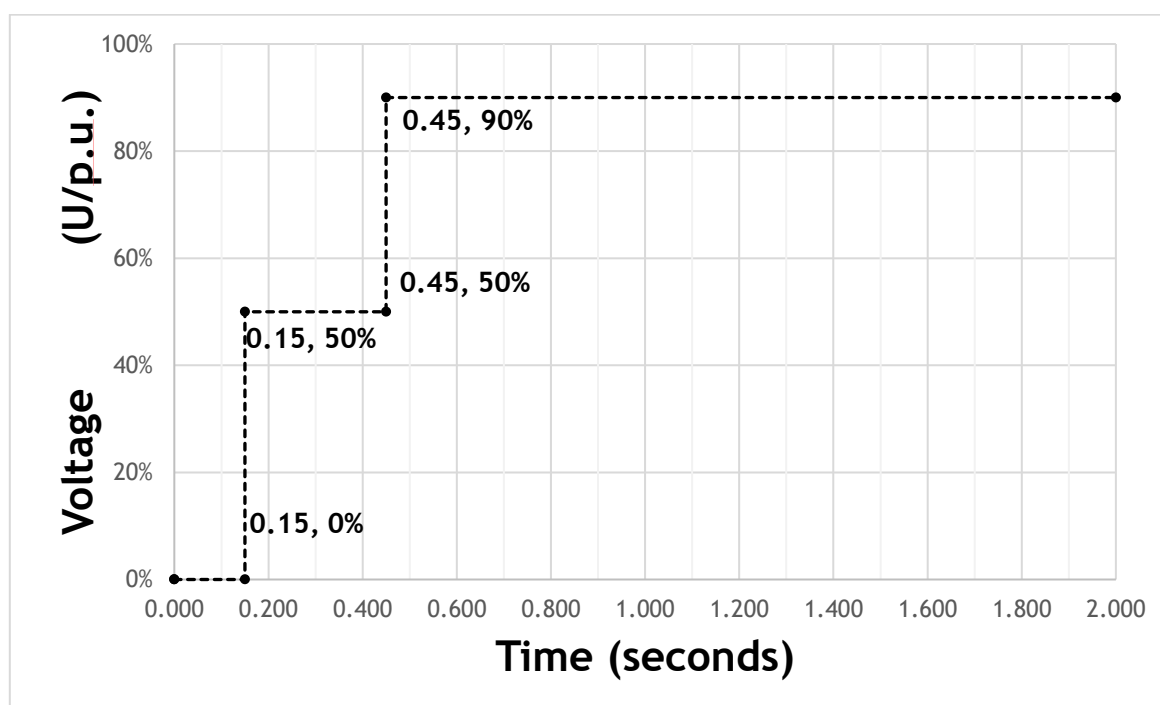


Figure 18 Required Voltage against time profile as proposed as part of forthcoming EirGrid and SONI Grid code modification proposal)

6.7. Active Power Consumption Recovery

The TSOs' proposal also includes requirements for how demand facilities should recover their active power consumption following fault clearance and voltage recovery, to help reduce the occurrence of over-frequency events and support system stability. After a fault is cleared and the voltage recovers to 0.9 per unit, demand facilities would be required to return to their pre-fault operating condition and maintain demand above 90% of the pre-fault value.

To determine the appropriate recovery time the TSOs conducted various detailed sensitivity studies, as outlined in Chapter 4. These studies indicated that a longer recovery time results in a more significant system imbalance, causing frequency and RoCoF violations. The maximum time required for demand facilities to restore 90% of the pre-fault demand is therefore proposed to be 500 milli-second. A 500 milli-second recovery time is consistent with the recovery time of Power Park Modules (wind farms, solar farms, and batteries) and HVDC interconnectors already specified in the Grid Code.

Requirement	All Demand facilities
Active Power Consumption recovery	Following clearance of the Fault Disturbance, the Demand Facility should return to at least 90% of its pre-fault Demand within 500 milliseconds of the Transmission System Voltage recovering to 90% of the nominal Voltage. The post Fault Disturbance ramp up rate for the Demand Facility, shall be coordinated and agreed between the TSO and the Demand Facility owner.

Table 17 Active Power Consumption recovery

6.8. Structure of Modification Proposals

Following feedback received as part of the stakeholder review of version 1.0 of this document issued on 17 October 2025, and further assessment of the processes required by the DCC in the application of DCC requirements to non-DCC facilities, the TSOs now propose to split the modifications into two separate parts.

Modification 1: incorporating the Rate of Change of Frequency (section 6.5), Voltage Fault Ride Through (section 6.6) and Active Power Consumption Recovery (section 6.7) requirements which are not currently DCC requirements and as such would represent new requirements for all Demand Facilities.

Modification 2: incorporating the Frequency and Voltage standards (section 6.4) which require the application of DCC standards to non-DCC facilities.

Modification 1 will be progressed initially by the TSOs. Modification 2 will follow the processes as required by the DCC, as appropriate, and in coordination with the requirements of the relevant regulator.

6.9. Grid Code Derogation processes

The Ireland and Northern Ireland Grid Codes allow for users to apply for a derogation to a particular Grid Code standard which will be considered by the relevant TSO, and a decision taken by the relevant Regulator as to whether a derogation should be approved or not. There are slightly different processes in place for demand facilities installed under DCC requirements and non-DCC demand facilities.

6.9.1. EirGrid Grid Code Derogation process

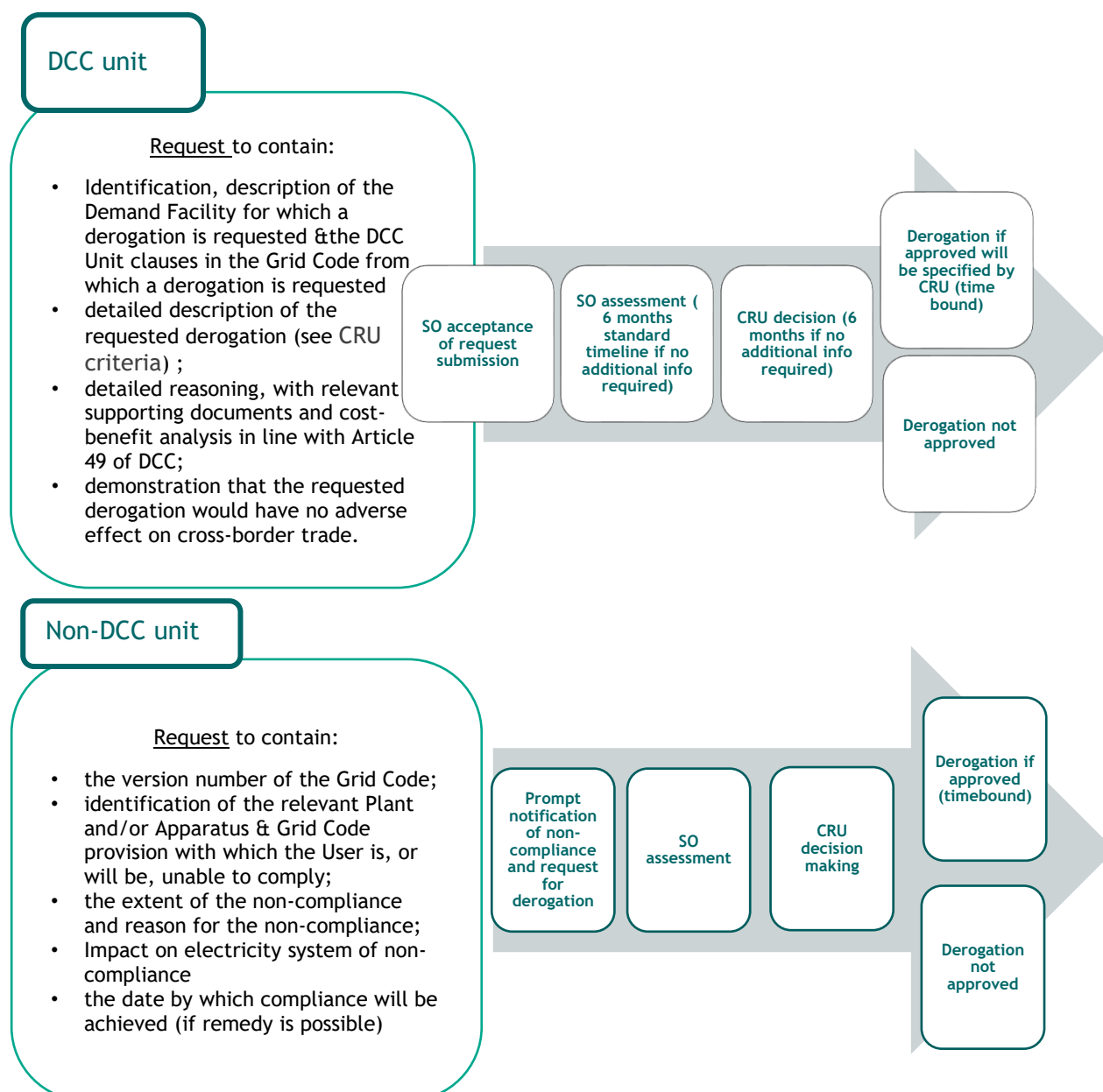
For facilities connected or connecting to the transmission system in Ireland the relevant links to the derogation forms are:

[GC9-1 Derogation Application Form](#) for units connected before 7th September 2019

[CNCD2 - Derogation Application Form](#) for units connected after 7th September 2019

EirGrid will assess each request for derogation and submit an assessment of the requested derogation and the resultant associated technical and operational considerations to the CRU. The CRU will make the final decision on whether the derogation request will be approved or rejected.

A summary of the required information and processes associated with the EirGrid Grid Code derogation request process is provided below:

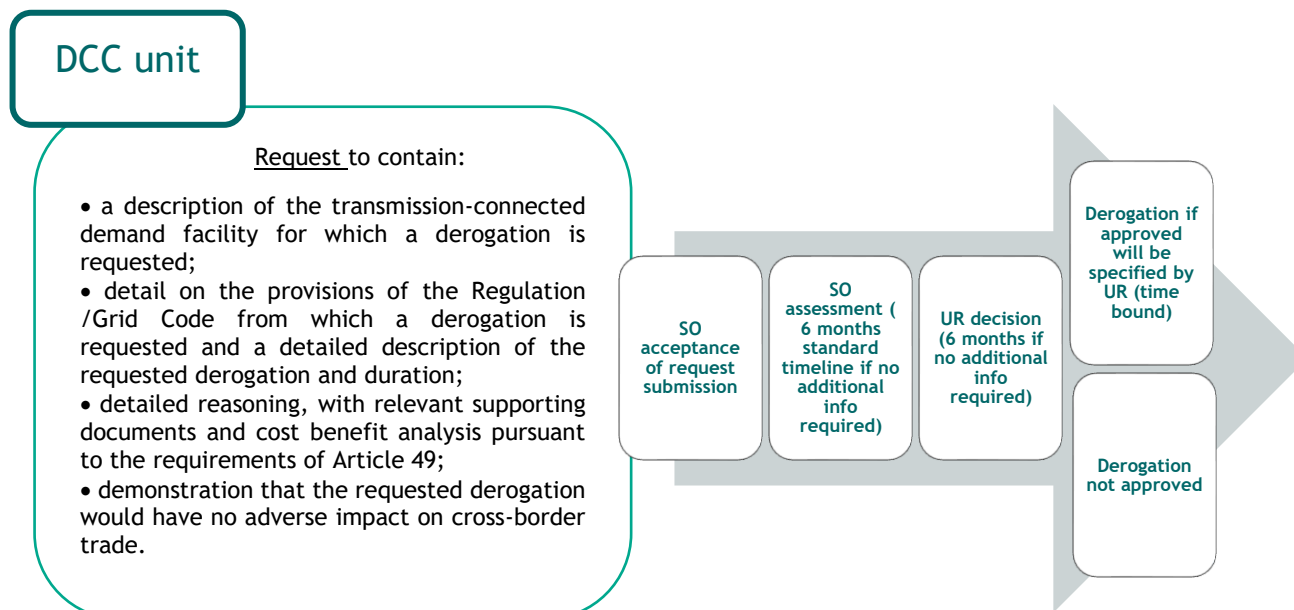


6.9.2. SONI Grid Code Derogation process

For facilities connected or connecting to the transmission system in Northern Ireland the Utility Regulator has provided [detailed guidance](#) on Derogation procedures, and the relevant Derogation Request template is available [here](#).

For users seeking a derogation to DCC standards the request is submitted to SONI, and SONI will conduct an assessment of the requested derogation and the relevant technical and operational considerations. This assessment is then submitted to the Regulator who makes the final decision on whether the derogation request will be approved or rejected.

A summary of the required information and processes associated with the SONI Grid Code Derogation requests is provided below:



7. Next Steps

We are grateful to industry and their representative bodies for the constructive engagement so far including the feedback on the previous version of this document issued on 17 October 2025. Their involvement and input is vital. As we work together with industry, government and regulators on this critical issue, our priority remains to ensure system stability, power quality and security of supply for all users of the power system.

The TSOs continue to engage and collaborate with industry and will host another webinar (scheduled for 26 November 2025), bi-lateral meetings, and continue engagement through the relevant forums.

Details of this webinar will be shared separately. As with previous webinars, we invite industry representatives to present at this event (subject to prior agreement with EirGrid and SONI) and we will engage in an open Q&A session.

Appendices

Appendix 1 International System Events

The following section summarises two recent events that occurred in the USA in which a fault triggered the loss of significant quantities of data centre demand.

Large Load Demand Reduction in Texas, USA.

On 7 December 2022, a significant load reduction event occurred in the Electric Reliability Council of Texas (ERCOT) grid in the United States, resulting in a reduction of approximately 1,600 MW. This event was triggered by multiple faults on 138 kV lines near Odessa, including a three-phase fault due to a circuit breaker failure. The load reduction included a mix of large loads such as data centres, oil/gas, and other industrial consumers.

Following the event's demand reduction, the system frequency spiked to 60.235 Hz, resulting in tripping of two thermal generation units with a combined capacity of 112 MW. As the system occurred during nighttime hours, solar photovoltaic did not contribute to system balancing. The system frequency recovered to 60 Hz within 12 minutes and 30 seconds.

Large Load Demand reduction in US Eastern Interconnection region

A recent US NERC (North American Electricity Reliability Council) report²⁶ has provided details of a similar loss of large volumes of load in the Eastern Interconnection region due to voltage sensitive protection settings at data centre sites.

On 10 July 2024, a 230 kV transmission line fault led to a simultaneous loss of approximately 1,500 MW of voltage-sensitive load that was not anticipated.

The incident began when a lightning arrestor failed on a 230 kV transmission line in the region, with multiple auto-reclose events resulting in 6 successive system faults in an 82-second period. The protection systems detected these faults and cleared them properly. The shortest fault duration was the initial fault at 42 milliseconds, and the longest fault duration was 66 milliseconds. The voltage magnitudes during the fault ranged from .25 to .40 per unit in the load-loss area.

Coincident to the fault event approximately 1500MW of large load (identified as data centre load) in the vicinity disconnected from the grid - and did not reconnect immediately post-fault clearance. As a result, both frequency and voltage levels rose e.g. voltage rose to 1.07 per unit, and required system operator action to reduce voltage, while Frequency rose to a high of 60.047 Hz and took approximately 4 mins to settle back to 60.0 Hz.

NERC highlights that the scale of the load lost in this and similar incidents, and the consequential risk to system stability is of increasing concern for system operators. NERC have now established a Large Load Taskforce²⁷ to investigate this topic further and develop recommendations for system operators. Under this Large Load Taskforce, NERC have published a White Paper entitled 'Characteristics and Risks of Emerging Large Loads'²⁸.

²⁶ [NERC Incident Review Large Load loss July 2024](#)

²⁷ <https://www.nerc.com/comm/RSTC/Pages/LLTF.aspx>

²⁸ [White Paper Characteristics and Risks of Emerging Large Loads](#)

Appendix 2 International Standards

This section provides an overview of existing and developing standards related to fault ride through requirements by various TSOs worldwide. Figure 19 overlays some of these standards with the proposed EirGrid/SONI standards for low voltage ride-through.

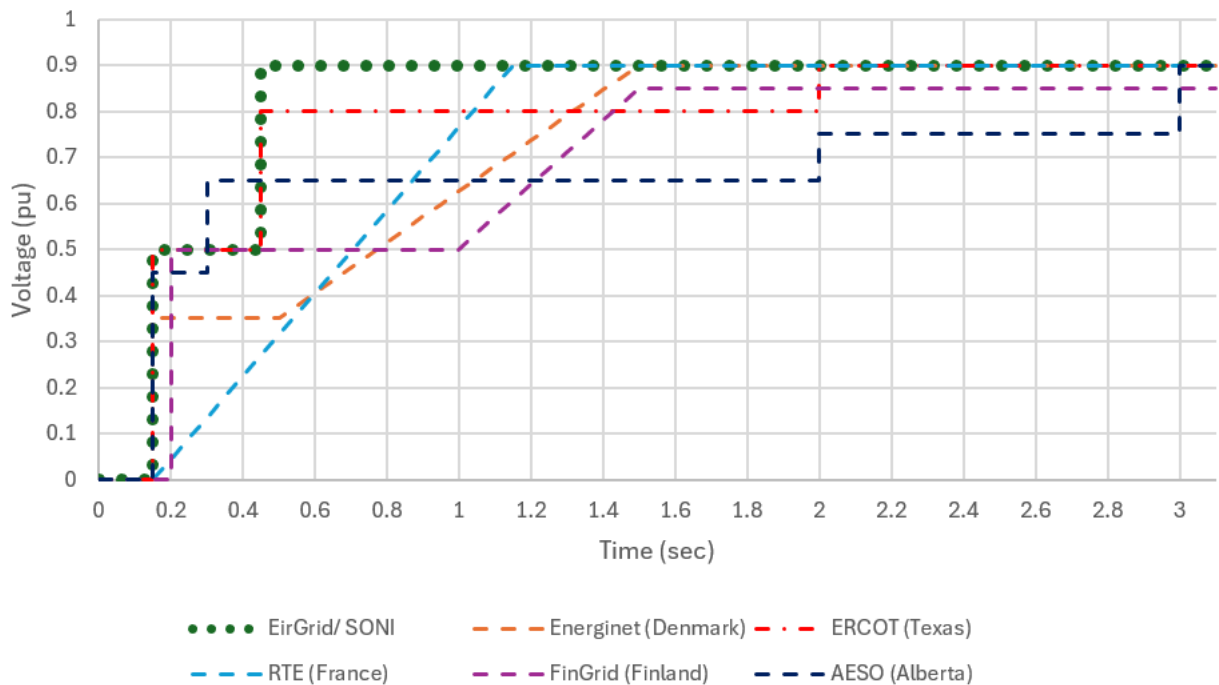


Figure 19 Comparison of Low Voltage Ride Through (LVRT) curves across selected jurisdictions, illustrating the minimum voltage levels and corresponding time durations during which grid-connected systems are required to remain operational during voltage dips

Further details on the individual standards are provided in the following sections.

France - RTE

In 2024, RTE (Réseau de Transport d'Électricité) introduced new fault ride through requirements²⁹ within its grid code. These requirements are specifically targeted at large energy users, primarily data centre customers. The following summarises the RTE requirements:

Overvoltage Ride-Through: Consumption units must remain connected if the RMS voltage at the connection point exceeds the following values

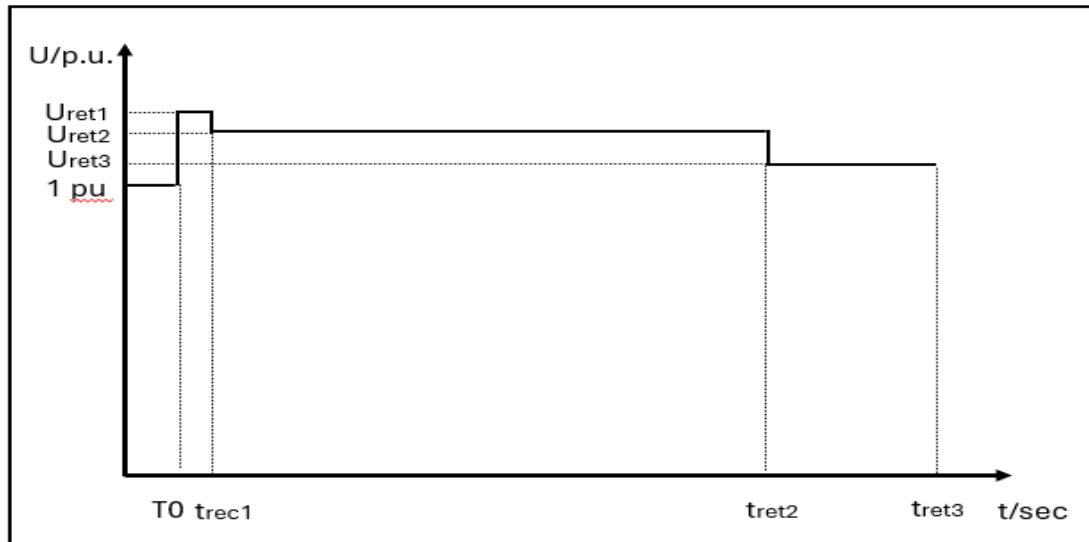


Figure 20 Overvoltage Ride-Through

Voltage Parameters (pu)		Time Parameter (Seconds)	
Uret 1	1.3	T0	0
Uret 1	1.3	Tret 1	0.1
Uret 2	1.25	Tret 2	2.5
Uret 3	1.15 (1.1 for 400kV)	Tret 3	30

Table 18 Overvoltage and time parameters as implemented by RTE France

Undervoltage ride through: During undervoltage events, consumption units connected to the grid must remain operational if the root-mean-square (RMS) voltage dip at the connection point exceeds the specified values in the provided table. These values define the voltage and time duration thresholds for which the unit must maintain grid connection.

²⁹ services-rte.com/files/live/sites/services-rte/files/documentsLibrary/Article_8.3.5_CdC_des_capacites_constructive_d_une_installation_de_consommateurs_1897_fr

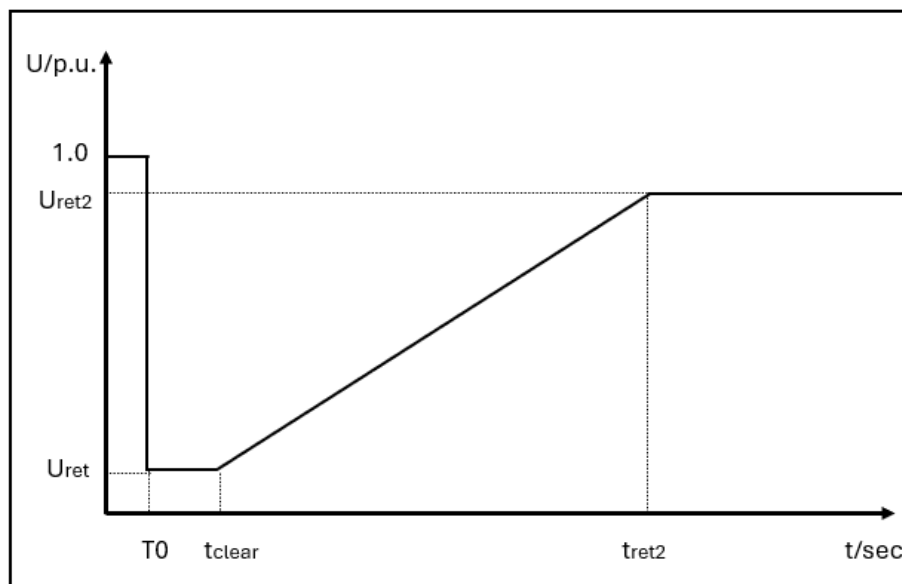


Figure 21 Undervoltage ride through

Voltage Parameters (pu)		Time Parameter (Seconds)	
Uret	0.05	T0	0
Uret	0.05	Tclear	0.15
Uret 2	0.9	Tret 2	1.15

Table 19 Undervoltage and time parameters as implemented by RTÉ France

Europe - ENTSO-E

The European Network of Transmission System Operators for Electricity “ENTSO-E” proposed to the European Union Agency for the Cooperation of Energy Regulators “ACER” to include a new data centre demand category (110 kV and above) requirements³⁰ in to Network Code on Demand Connection (DCC 2.0). Their proposal is summarised below.

While this proposal was not accepted by ACER at the time, ACER acknowledged that additional requirements could be introduced at a national level if required to ensure system stability. Such additional requirements can be prescribed in the connection agreement or in the national regulatory framework.

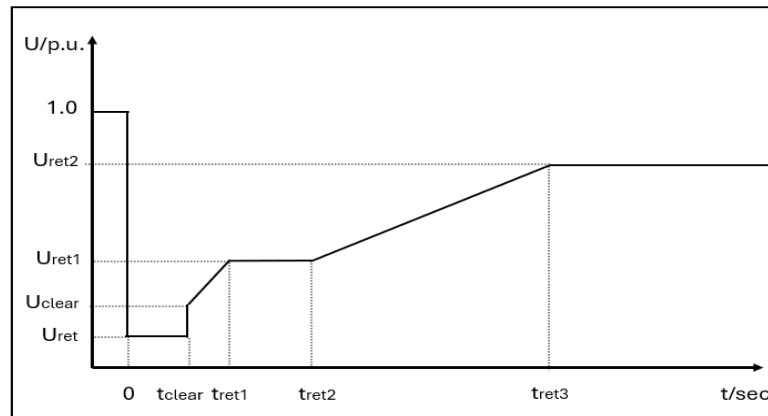


Figure 22 ENTSO-E Proposed Fault Ride through requirements

Voltage Parameters (pu)		Time Parameter (Seconds)	
Uret	0	T0	0.14-0.15 (or 0.14-0.25 if system protection and secure operation so require)
Uclear	Uret	Trec 1	Tclear
Uret 2	Uclear	Trec 2	Trec1
Uret 3	0.85	Tret 3	1.5-3.0

Table 20 Undervoltage and time parameters as proposed by ENTSO-E

³⁰ <https://acer.europa.eu/sites/default/files/2023-09/ENTSO-E.zip>

USA - ERCOT

In recent years, ERCOT has observed a growing reliability concern related to the performance of Large Electronic Loads (LELs), particularly during common voltage disturbances. Unlike other large loads that typically ride through such events, many LELs—especially those associated with data centres and cryptocurrency mining facilities—have been found to disconnect almost instantaneously from the grid. These disconnections, often lasting several seconds or more, pose a significant risk to system stability. ERCOT has engaged with multiple LEL owner/operators and equipment manufacturers to better understand current ride-through capabilities and the design of Uninterruptible Power Supply (UPS) systems.

To quantify the potential impact, ERCOT conducted several studies. One study showed that an instantaneous loss of 2,600 MW of load under certain system conditions could cause the system frequency to rise to 60.4 Hz, with RoCoF exceeding 5 Hz/sec—conditions that could trigger cascading generator outages. Another study focused on West Texas, where a three-phase fault could result in the loss of up to 1,500 MW of operational LELs. These findings underscore the critical need for LELs to ride through disturbances to prevent system-wide frequency instability. As a result, ERCOT is evaluating mitigation strategies, including the use of System Operating Limits (SOLs), and is developing voltage ride-through performance requirements for future LELs. While existing LELs are not currently required to meet these proposed standards to remain operational or receive energization approval, future facilities will need to comply to ensure grid reliability. These efforts are part of an ongoing discussion with stakeholders to define acceptable ride-through performance and support the secure integration of LELs into the ERCOT system.

Below is a summary of the voltage ride-through performance requirements that ERCOT is currently proposing for discussion with LEL owners/operators and equipment manufacturers.

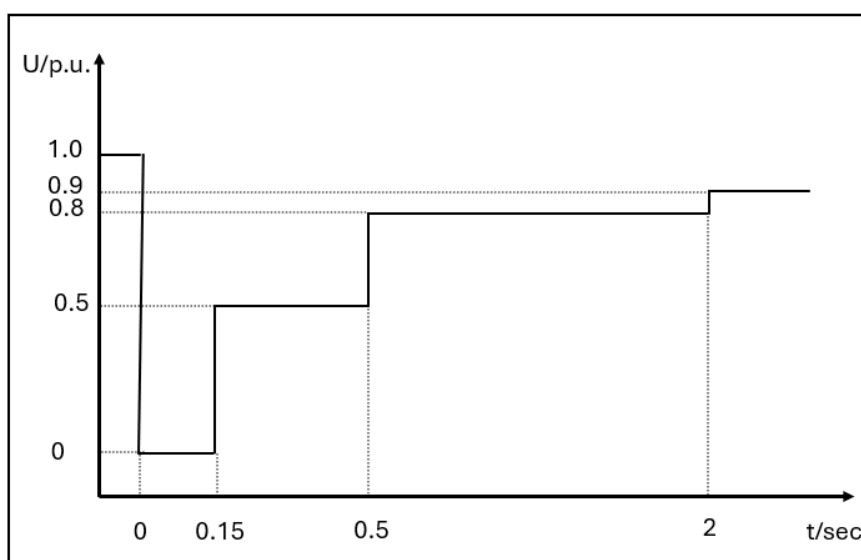


Figure 23 ERCOT voltage ride through performance requirements

ERCOT is also proposing requirements for active power recovery, while loads may reduce their power consumption during such events, they remain connected to the system. preferably, LELs should continue consuming power from the grid during shallow voltage sags between 0.5 and 0.8 per unit (pu), with the reduction in consumption proportionally reflecting the depth of the voltage dip. In cases of deeper voltage sags—below 0.5 pu—where the rectifier is unable to deliver active power, the load may temporarily transition to UPS support. However, once the voltage recovers, the load is expected to return at least 90% of its pre-disturbance grid consumption within one second.

Finland - FinGrid

FinGrid, the transmission system operator of Finland, is introducing new fault ride-through requirements as part of its upcoming grid code update, aimed at enhancing the resilience of demand-side connections. These requirements target large energy consumers—such as data centres and power-to-gas facilities—ensuring they remain connected to the grid during short voltage dips and other disturbances. The update applies to all new demand facilities connecting to the power system, as well as existing facilities undergoing system modifications. The LVRT curve below illustrates the required performance envelope during and after a voltage disturbance:

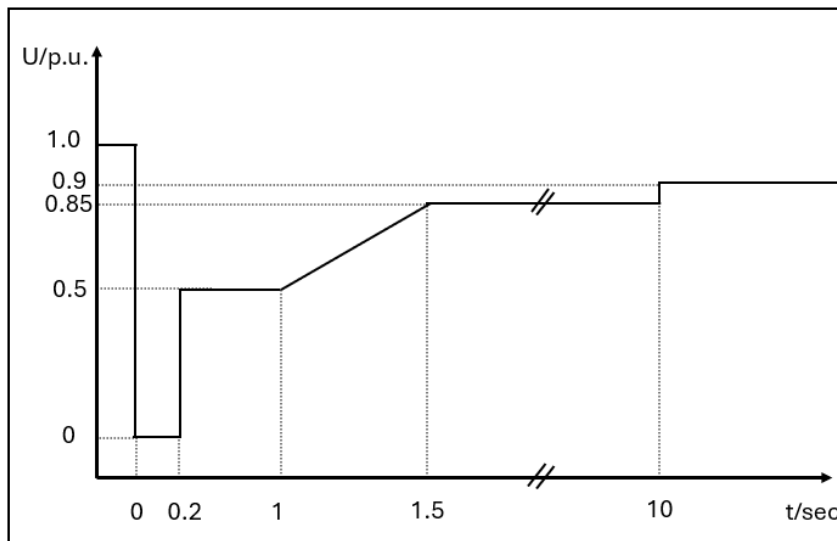


Figure 24 FinGrid required performance envelope during and after voltage disturbance

These measures are designed to support grid stability by ensuring that large loads do not disconnect or delay recovery during and after voltage disturbances. A key component of this update is the introduction of Low Voltage Ride Through (LVRT) requirements for data centres with a capacity exceeding 10 MW. These facilities must restore their active power consumption to pre-fault levels with defined accuracy and within a specified timeframe. Specifically, once the voltage at the point of common coupling recovers to 0.90 per unit (pu), the facility must return to at least its pre-disturbance active power level within 0.5 seconds.

Canada - AESO

The Alberta Electric System Operator (AESO) has proposed new fault ride-through requirements for data centres as part of its draft Connection Requirements for Transmission-Connected Data Centres (TCDC)³¹. These requirements aim to enhance grid reliability by ensuring that data centres remain connected during voltage disturbances and contribute to system stability throughout the recovery process.

The AESO's requirements apply to all existing and future data centres connected to the Alberta transmission system. Facilities must be capable of riding through voltage disturbances of the magnitude and duration specified in the LVRT curve below. These disturbances may result from events such as trip and auto-reclose operations on transmission lines or multiple faults during severe weather conditions.

³¹ [Connection Requirements for Transmission-Connected Data Centres | AESO Engage](#)

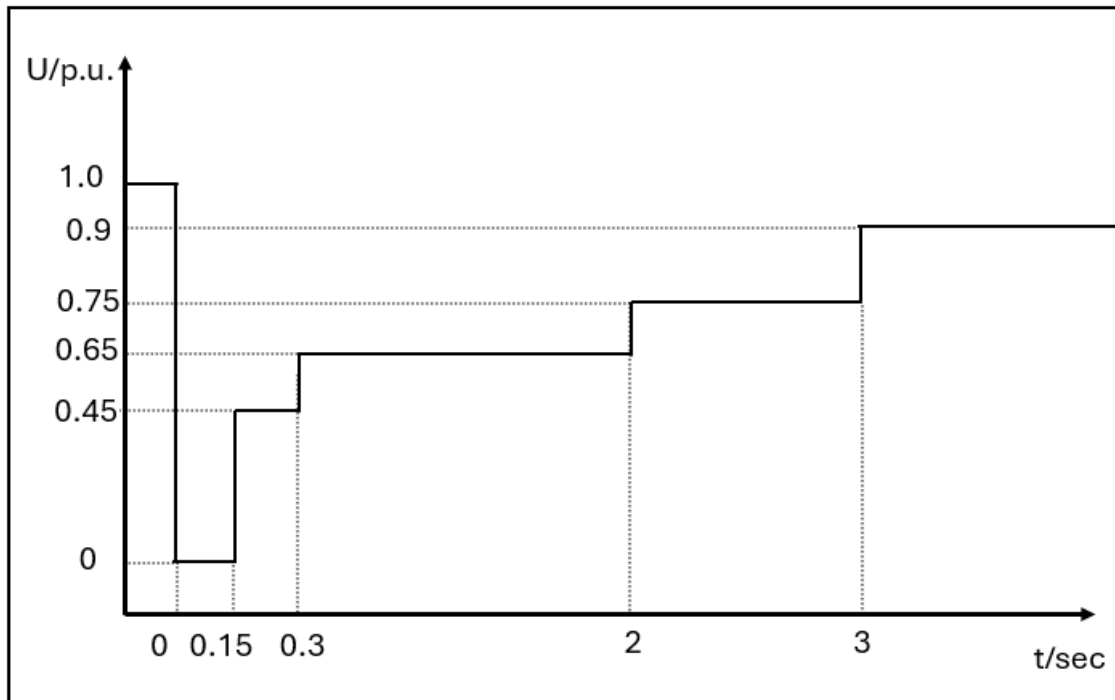


Figure 25 Proposed AESO fault ride-through performance envelope

To support grid recovery, data centres must restore their active power consumption once the voltage at the point of connection returns to the continuous operation level. The active power recovery time must be configurable within a range of 1.0 to 10.0 seconds, with a default setting of 1.0 second. In weak grid conditions, the AESO may require a slower recovery rate to mitigate oscillatory behaviour and maintain system stability.

Europe - ENTSO-E Power-to-Gas Connection Standards

ENTSO-E, recognizing rapid growth of Power-to-Gas (PtG) technology, has published a position paper³² addressing the urgent need for connection requirements for PtG facilities. With a potentially large number of PtG units connecting to electricity grids before comprehensive EU-wide network codes are fully established, ENTSO-E highlights the potential degradation of system robustness and operational reliability in the absence of coordinated technical specifications. Connecting these units without standardised and coordinated technical requirements could significantly impact grid stability. Therefore, the paper recommends that transmission system operators proactively establish minimum technical requirements at the national level. These requirements should encompass aspects such as fault ride through capability, ensuring PtG facilities remain connected during grid disturbances, robustness against Rate of Change of Frequency (RoCoF), maintaining stability during frequency fluctuation, and post active power recovery facilitating rapid restoration of power after any faults.

³² [ENTSO-E Position Paper on connection requirement for PtG Facilities](#)

Appendix 3 Existing requirements and proposed changes to EirGrid and SONI Grid Codes

Type	Non-DCC Connected Demand user- (EirGrid connected demand facilities only)	DCC Demand user (Existing SONI and EirGrid connected demand facilities and future connections)																
Requirements for operation at different Voltage ranges (Part of Modification 2)	<u>New requirement for non DCC EirGrid connected facilities</u> Remain synchronised to the Transmission System and operate within the ranges of the Transmission System Voltage at the connection point, for an unlimited time period, as specified below: <table><tr><th>Connection Voltage</th><th>Voltage range (unlimited operation)</th></tr><tr><td>400kV</td><td>0.9 p.u. - 1.05 p.u.</td></tr><tr><td>220kV</td><td>0.9 p.u. - 1.114 p.u.</td></tr><tr><td>110kV</td><td>0.9 p.u. - 1.118 p.u.</td></tr></table>	Connection Voltage	Voltage range (unlimited operation)	400kV	0.9 p.u. - 1.05 p.u.	220kV	0.9 p.u. - 1.114 p.u.	110kV	0.9 p.u. - 1.118 p.u.	<u>EirGrid Grid Code reference: CC7.4</u> Remain synchronised to the Transmission System and operate within the ranges of the Transmission System Voltage at the connection point, for an unlimited time period, as specified below: <table><tr><th>Connection Voltage</th><th>Voltage range (unlimited operation)</th></tr><tr><td>400kV</td><td>0.9 p.u. - 1.05 p.u.</td></tr><tr><td>220kV</td><td>0.9 p.u. - 1.114 p.u.</td></tr><tr><td>110kV</td><td>0.9 p.u. - 1.118 p.u.</td></tr></table>	Connection Voltage	Voltage range (unlimited operation)	400kV	0.9 p.u. - 1.05 p.u.	220kV	0.9 p.u. - 1.114 p.u.	110kV	0.9 p.u. - 1.118 p.u.
	Connection Voltage	Voltage range (unlimited operation)																
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220kV	0.9 p.u. - 1.114 p.u.																	
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400kV	0.9 p.u. - 1.05 p.u.																	
220kV	0.9 p.u. - 1.114 p.u.																	
110kV	0.9 p.u. - 1.118 p.u.																	
	<u>No non-DCC large demand facilities currently in Northern Ireland</u>	<u>SONI Grid Code reference CC.14.1.2</u> Remain synchronised to the Transmission System and operate within the ranges of the Transmission System Voltage at the connection point, for an unlimited time period, as specified below:																

		<table><tr><th>Connection Voltage</th><th>Voltage Range (unlimited operation)</th></tr><tr><td>400 kV</td><td>0.9 p.u. - 1.05 p.u.</td></tr><tr><td>275 kV</td><td>0.9 p.u. - 1.09 p.u.</td></tr><tr><td>110 kV</td><td>0.9 p.u. - 1.1 p.u.</td></tr></table>	Connection Voltage	Voltage Range (unlimited operation)	400 kV	0.9 p.u. - 1.05 p.u.	275 kV	0.9 p.u. - 1.09 p.u.	110 kV	0.9 p.u. - 1.1 p.u.																				
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110 kV	0.9 p.u. - 1.1 p.u.																													
Requirements for operation and different Frequency ranges (Part of Modification 2)	<u>New requirement for non DCC EirGrid connected facilities</u> Remain synchronised to the Transmission System and operate (without disconnecting) within the frequency ranges and time periods outlined below <table><tr><th><u>Frequency Range</u></th><th><u>Time Period</u></th></tr><tr><td>47 - 47.5 Hz</td><td>20 seconds</td></tr><tr><td>47.5 - 48.5 Hz</td><td>90 minutes</td></tr><tr><td>48.5 - 49 Hz</td><td>90 minutes</td></tr><tr><td>49 - 51 Hz</td><td>Unlimited</td></tr><tr><td>51 - 51.5 Hz</td><td>90 minutes</td></tr><tr><td>51.5 - 52 Hz</td><td>60 minutes</td></tr></table>	<u>Frequency Range</u>	<u>Time Period</u>	47 - 47.5 Hz	20 seconds	47.5 - 48.5 Hz	90 minutes	48.5 - 49 Hz	90 minutes	49 - 51 Hz	Unlimited	51 - 51.5 Hz	90 minutes	51.5 - 52 Hz	60 minutes	<u>EirGrid Grid Code reference CC.7.4.2.1 - SONI Grid Code reference -CC.14.1.1)</u> Remain synchronised to the Transmission System and operate (without disconnecting) within the frequency ranges and time periods outlined below <table><tr><th><u>Frequency Range</u></th><th><u>Time Period</u></th></tr><tr><td>47 - 47.5 Hz</td><td>20 seconds</td></tr><tr><td>47.5 - 48.5 Hz</td><td>90 minutes</td></tr><tr><td>48.5 - 49 Hz</td><td>90 minutes</td></tr><tr><td>49 - 51 Hz</td><td>Unlimited</td></tr><tr><td>51 - 51.5 Hz</td><td>90 minutes</td></tr><tr><td>51.5 - 52 Hz</td><td>60 minutes</td></tr></table>	<u>Frequency Range</u>	<u>Time Period</u>	47 - 47.5 Hz	20 seconds	47.5 - 48.5 Hz	90 minutes	48.5 - 49 Hz	90 minutes	49 - 51 Hz	Unlimited	51 - 51.5 Hz	90 minutes	51.5 - 52 Hz	60 minutes
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Fault ride through requirement (New requirement, part of Modification 1)	Demand Facilities shall remain connected to the Transmission System during and following any Fault Disturbance on the Power System which results in a Voltage deviation which remains on or above the voltage-against-time profile specified in Figure CC.7.4.3.2 (EirGrid Grid Code reference- SONI Grid Code reference tbc) at the Connection Point. The voltage-against-time profile specifies the required capability as a function of voltage and Fault Ride-Through Time at the Connection Point before, during and after the Fault Disturbance.
RoCoF requirement (New requirement, part of Modification 1)	Remain connected to the Transmission System during rate of change of Transmission System Frequency of values up to and including 1Hz per second as measured over a rolling 500 milliseconds period. (Voltage dips may cause localised RoCoF values in excess of 1 Hz per second for short periods, and in these cases, the Fault-Ride Through clause CC.7.4.3.2 supersedes this clause (CC.7.4.3.1) EirGrid Grid Code reference- SONI Grid Code reference CC.14.1.5
Active Power consumption recovery requirement (New requirement, part of Modification 1)	Following clearance of the Fault Disturbance, the Demand Facility should return to at least 90% of its prefault Demand within 500 milliseconds of the Transmission System Voltage recovering to 90% of the nominal Voltage. The post Fault Disturbance ramp up rate for the Demand Facility, shall be coordinated and agreed between the TSO and the Demand Facility owner.

