Fault Ride Through / Active Power Recovery / Rate of Change of Frequency

EirGrid Update including Assessment of System Service / Grid Solution Alternatives

26 June 2026

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Glossary of terms

Acronym	Meaning
APR	Active Power Recovery
BESS	Battery Energy Storage System
CRU	Commission for Regulation of Utilities
ESB	Electricity Supply Board
FRT	Fault Ride Through
HVDC	High Voltage Direct Current
Hz	Hertz (unit of frequency)
kV	Kilo-Volt
LSAT	Look-Ahead Security Assessment Tool
MEC	Maximum Export Capacity
MIC	Maximum Import Capacity
MVA	Mega Volt-Ampere
MW	Mega Watt
NESO	National Energy System Operator
OEM	Original Equipment Manufacturer
RMS	Root Mean Square
RoCoF	Rate of Change of Frequency
SEMO	Single Electricity Market Operator
SONI	System Operator for Northern Ireland
STATCOM	Static Synchronous Compensator
TSO	Transmission System Operator
UPS	Uninterruptible Power Supply

1. Executive Summary

EirGrid must balance electricity supply and demand at all times, operating within prescribed standards to keep Ireland's power system stable and secure. A current risk EirGrid is managing relates to the collective response of most data centres to fault events occurring on the transmission system. EirGrid has engaged extensively with industry since 2022 on this issue and is currently managing this risk through operational measures while working with industry and stakeholders on enduring solutions which are urgently required.

This information paper provides industry with updates on a number of aspects of the Fault Ride-Through (FRT) issue that have evolved since the publication of the Large Demand Facility Fault Ride Through Issue and Proposed Solutions Information Paper of November 2025[1] and the submission of Grid Code modification proposals, MPID345, for Fault Ride-Through (FRT) / Active Power Recovery (APR) and Rate of Change of Frequency (RoCoF) to CRU on 1 April 2026[2]. These updates include:

- Further power system analysis that EirGrid has undertaken into System Service / Grid Solutions as alternatives to the delivery of FRT/APR/RoCoF requirements at demand facilities.
- Additional options for the data centre demand data source to be used for the calculation and monitoring of the Demand Utilisation Threshold. We anticipate that CRU will take into account these options in its deliberations on the MPID345 Compliance and Derogation Framework proposals.
- Notification of a new highest monthly average data centre demand level of approximately 900 MW recorded in May 2026 with a daily peak of approximately 1000 MW recorded so far in June 2026. This continued increase in non-FRT capable demand has brought the All-Island power system to its Load Rejection Limit[3] at times based solely on data centre demand utilisation.
- An overview of the most recent fault event on 6 June 2026 that resulted in a maximum aggregate data centre demand reduction of approximately 480 MW. This was the largest FRT event to date.
- Updates on the operational measures being taken by EirGrid to manage the growing risk to the security of the power system that the FRT issue is presenting.

EirGrid is also continuing to progress the delivery of additional solutions (System Services / Grid Solutions). These include procurement of synchronous condenser technology (Low Carbon Inertia Services) to deliver more inertia, and implementation of the Future Arrangements for System Services programme to deliver new frequency response services. EirGrid has previously stated that, while these new capabilities will assist to an extent in mitigating the FRT issue, they are not considered adequate on their own to address the impacts of lack of FRT capability at demand facilities as it would introduce unacceptable power system risk and operational complexity.

To test this position again, EirGrid has undertaken further analysis to consider a scenario in which additional System Service / Grid solutions are solely used to address the FRT issue. The analysis considers the impact of additional inertia, fast frequency response and reactive power compensation using representative dynamic simulations. The power system operational complexity and risks associated with such an approach are also considered.

[1] MPID345-Large-Demand-Facility-Fault-Ride-Through-Issue-and-Proposed-Solutions-EirGrid-and-SONI-Information-Paper-November-2025.pdf
[2] Grid Code Modifications | The Grid Code | EirGrid
[3] The Power System Load Rejection limit (from Large Energy Users and Interconnector Exports) should not exceed 900 MW – as published in the EirGrid/SONI Weekly Operational Constraints Update published here: General Publications | SEMO

This analysis concludes that System Service / Grid solutions alone do not offer credible alternatives to the implementation of FRT/APR/RoCoF capability at demand facilities. Attempting to secure for instantaneous demand reductions of the magnitude modelled would introduce an unacceptable level of complexity and risk to the security of the All-Island power system and threaten security of supply for all electricity consumers. This approach would also tie-up grid capacity and connections that would significantly inhibit the ability of the grid to accommodate demand growth and new demand connections.

The conclusion that the FRT issue cannot be resolved solely by System Service / Grid solutions is reflected in the development of equivalent FRT requirements for demand facilities progressing in multiple other jurisdictions. EirGrid is not aware of any jurisdiction solely relying on System Service / Grid Solutions to resolve significant fault ride through challenges, or manage large imbalances, such as those that exist on the All-Island power system.

It remains critical that implementation of Grid Code Modification proposal MPID345, supported by the associated Compliance and Derogation framework and the implementation of solutions by customers, are progressed as quickly as possible to manage the increasing risk to the security of the All-Island power system and reduce the operational and commercial impacts of the mitigation measures being taken on customers.

EirGrid will continue to engage with industry on this challenging issue through industry webinars, bi-lateral meetings and other relevant forums. EirGrid recognises the progress made by industry in regard to demand facility solutions and will continue to work with industry to support delivery of solutions.

2. Introduction

This information paper provides industry with updates on a number of aspects of the Fault Ride-Through (FRT), Active Power Recovery (APR) and Rate of Change of Frequency (RoCoF) issue and presents further power system analysis that EirGrid has undertaken into System Service / Grid Solutions as alternatives to the delivery of FRT/APR/RoCoF requirements at demand facilities.

The updates reflect the evolution of the issue since the publication of the Large Demand Facility Fault Ride Through Issue and Proposed Solutions Information Paper of November 2025[4] and the submission of Grid Code modification proposal MPID345 to the CRU on 1 April 2026[5], which incorporates the proposed requirements for Fault Ride Through (FRT), Active Power Recovery (APR), and Rate of Change of Frequency (RoCoF). These updates are provided in section 3.

In the Large Demand Facility Fault Ride Through Issue and Proposed Solutions Information Paper of November 2025, we set out three pillars of actions for mitigating / addressing the FRT issue. These are:

1. Implementation of operational measures to manage the current issue;
2. Consideration of additional System Services / Grid solutions to mitigate the issue; and,
3. Development of Fault Ride Through (FRT), Active Power Recovery (APR) and Rate of Change of Frequency (RoCoF) requirements for demand facilities.

Progress has been made under all these pillars since publication of the Information Paper in November 2025, and a status update on each is provided in section 4.

In section 5 of this paper, we focus on additional technical analysis EirGrid has undertaken to consider the potential benefits of additional System Service / Grid solutions to support the management of the FRT issue. The analysis considers the impact of additional inertia, fast frequency response and reactive power compensation using a representative operational scenario and dynamic simulations to assess power system performance following a large disturbance involving the sudden loss of demand.

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[4] MPID345-Large-Demand-Facility-Fault-Ride-Through-Issue-and-Proposed-Solutions-EirGrid-and-SONI-Information-Paper-November-2025.pdf

[5] Grid Code Modifications | The Grid Code | EirGrid

3. FRT Updates

The following provides a summary of key FRT related developments / updates since the publication of the Large Demand Facility Fault Ride Through Issue and Proposed Solutions Information Paper of November 2025 and / or the submission of Grid Code modification proposals, MPID345, for Fault Ride-Through (FRT) / Active Power Recovery (APR) and Rate of Change of Frequency (RoCoF) to CRU on 1 April 2026.

3.1 Submission of Grid Code Modification Proposal MPID345

Following an extensive period of engagement with industry, EirGrid submitted its Grid Code modification proposals, MPID345, for Fault Ride-Through (FRT) / Active Power Recovery (APR) and Rate of Change of Frequency (RoCoF) to CRU on 1 April 2026. This submission was also accompanied by a Compliance and Derogation Framework proposal that sets out arrangements for managing the implementation of the Grid Code modification in a practical manner that accounts for the implementation challenges flagged by industry. Full proposal details and supporting information can be found under Grid Code Modification Proposal MPID345[6].

The proposals remain under consideration by CRU.

3.2 Demand Utilisation Threshold Approach

3.2.1 Background

As part of the Compliance and Derogation Framework proposal submitted to CRU (Sections 4.3.6 and 4.3.7) EirGrid proposed arrangements to apply a limit to non-FRT capable demand through the application of Demand Utilisation Thresholds (DUTs) at data centre facilities availing of the proposed 24-month derogation period. Our proposals set out the calculation methodology for the DUTs. Estimated DUTs based on this methodology have been communicated to all transmission connected data centres, on the basis that these estimated DUTs were indicative and not finalised.

3.2.1 Review of Approach

During engagement with customers, some data centre customers provided feedback on the demand utilisation data source being used under the proposed methodology, namely the use of SCADA data to determine and monitor the DUT.

In response to this feedback, we have examined the use of billing / metering data as an alternative to SCADA data to set and monitor DUTs. Following this review, EirGrid has identified three potential ways of calculating DUTs as set out in Table 1 below.DUT Setting Options

[6] Grid Code Modifications | The Grid Code | EirGrid

Options for setting DUT	Key Considerations	DUT Setting Source
Option 1: Existing approach as communicated in the Compliance and Derogation Framework submission to CRU of 1 April 2026	Original basis used for determining DUTs for transmission connected data centres. Under this approach there would be no change to DUT estimates already communicated to customers. However, as the data sources used (TSO SCADA) is primarily used for operational purposes, it may not align with customer meter data and is not visible to customers. This approach allows for temporary 10 % peaking above the DUT and sets a fixed allowance for distribution connected data centres.	SCADA
Option 2: Use of Meter Data	DUTs for transmission connected data centres determined using metering data (maintaining the highest monthly average from 2025 approach). This approach would result in changes to DUT estimates for all customers. Meter data is validated as it is used for billing purposes. Meter data is available to customers via their suppliers. As for Option 1, this approach allows for temporary 10 % peaking above the DUT. Adjusted allowance for distribution connected data centres.	Metering
Option 3: Higher of the DUT determined under Option 1 and Option 2	DUTs for transmission connected data centres determined using the higher of the DUT determined under Option 1 (SCADA data) and Option 2 (metering data). Change to DUT estimates for some customers but no customer receives a lower DUT than estimate previously provided in line with Option 1. Adjusted allowance for distribution connected data centres. In order to facilitate the overall increase in aggregate DUTs that this approach results in, it is necessary to reduce the Margin for Peaks and customers would only be allowed to temporarily peak to 6.5 % above their DUT, a reduction from the 10 % allowed in Option 1 and Option 2. This reduction results in less flexibility for customers seeking to use short term peaking.	Metering/SCADA

Table 1 Options for setting DUT

3.2.2 Monitoring

EirGrid is proposing a dual data source approach for monitoring reflecting the different purposes and time scales involved:

- Real-time operational monitoring: For real-time operational monitoring of demand utilisation, EirGrid will use SCADA data as it provides immediate visibility of system conditions that is required for EirGrid to monitor and respond to changes in demand utilisation in real-time for the purposes of managing the security of the power system.
- DUT compliance monitoring: For purposes of assessing compliance with the DUT on a monthly basis, EirGrid will use metering data. Metering data is available to customers via their supplier and is the most accurate reflection of actual demand utilisation at each facility.

3.3 Data Centre Demand Growth

Data Centre demand has continued to grow from the peak monthly average of 800 MW reported in the November 2025 information paper. In May 2026, the average monthly data centre demand for all 110 kV and above connected data centres (at transmission and distribution level) was approximately 900 MW with an instantaneous peak in May 2026 of approximately 950 MW. So far in June 2026, a peak of approximately 1000 MW has been recorded.

EirGrid estimates that 90% of this demand could drop off the grid for certain credible faults on the transmission network. This means that, with 1000 MW of data centre demand recorded in June 2026, the reduction in data centre demand for a credible fault could be at the power system Load Rejection limit of 900 MW[7]. At this level, additional operational measures need to be taken by EirGrid to ensure that the Load Rejection limit is not exceeded, see section 4.1.

3.4 Latest Fault Incident

A further significant data centre demand loss incident occurred at 05:03 on 6 June 2026. Approximately 480 MW of data centre demand dropped off the grid for a single-phase fault event at a 220 kV station in central Dublin. This demand loss represents the most significant FRT-related demand loss event experienced to date and reflects the impact of the continued growth in data centre demand that is not FRT capable.

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 %
6 June 2026	**Dublin: Poolbeg 220 kV Reactor Fault**	**480 MW**	**52 %**

All of the contingency events observed to date were single-phase faults, for which EirGrid managed effectively to keep the power system safe and secure. For a three-phase fault, significantly higher demand reductions would be observed with our analysis (which is based on site specific model data) indicating that 90 % of data centre demand could reduce for other credible transmission system faults.

This further incident highlights that continued growth in non-FRT capable demand is increasing the level of potential imbalance on the power system and, as a consequence, increasing the risk to the security of the power system.

[7] The Power System Load Rejection limit (from Large Energy Users and Interconnector Exports) should not exceed 900 MW – as published in the EirGrid/SONI Weekly Operational Constraints Update published here: [General Publications | SEMO]

3.5 Data Centre Modelling

EirGrid hosted an industry information session on demand facility modelling requirements on 19 May 2026. At this session EirGrid highlighted the need for accurate dynamic models of demand facilities to ensure the secure, reliable and efficient operation and planning of the power system.

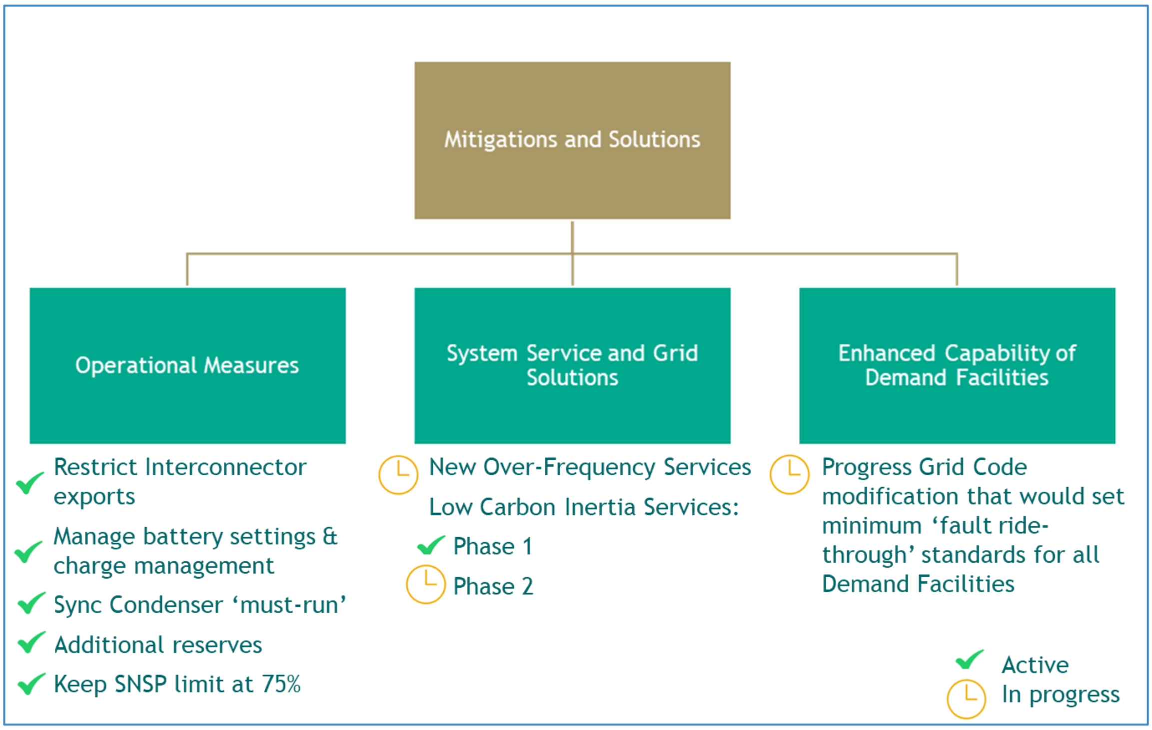
All demand facilities connected to the power system after 1st June 2016 or demand facilities that have undergone significant refurbishment that materially affects the dynamic performance of their facility, are required to provide dynamic models to EirGrid (reference EirGrid Grid Code PC.A8). Demand facility owners should contact their EirGrid account manager if they have queries about this requirement.

4. FRT Mitigations and Solutions Update

As set out in the FRT Information Paper of November 2025, EirGrid's approach to managing and resolving the FRT 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 being taken 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 to reduce total level of potential demand loss, as well as enhancement of over-frequency support capability and increased running of a synchronous condensers to provide more reserves and inertia on the power system. These operational measures continue to be monitored for effectiveness with the implementation of additional measures possible over the short to medium term in response to EirGrid's 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' requirements that would apply to large demand facilities. EirGrid submitted Grid Code Modification proposal MPID345[8] to CRU on 1 April 2026.

Progress has been made in many of these areas since the publication of our FRT Information Paper in November 2025. A summary of the steps being taken and their current status is provided in the figure below and in more detail in the following sections. Actions in all these areas are required to ensure that the TSOs can continue to 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.



[8] https://cms.eirgrid.ie/sites/default/files/publications/MPID345-Demand-Facilities-FRT-Recommendation-Paper-01042026.pdf

4.1 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 electricity 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.

A summary of the mid-June 2026 status of operational measures, both active and under consideration, is presented in the table below.

Mitigation Measure	Status	Description
Load Rejection Limit	Active	A limit of 900 MW has been set as the maximum demand loss that can be secured for. This demand loss can be made up of a combination of an individual HVDC interconnector export plus data centre demand that would be lost for a credible fault event.
Restrict Interconnector Exports	Active	Counter-trading on the three HVDC Interconnectors with GB to reduce exports given the potential export loss (which is equivalent to demand loss) for a fault at an interconnector also triggering data centre demand reduction.
Increased frequency responsiveness of wind and solar	Active	The frequency deadband on wind/solar[9] generation units in Ireland has been adjusted to make these units more responsive to frequency events triggered by a FRT event. This assists in maintaining the frequency Zenith, caused by large demand reductions, within operational limits.
Increased Inertia	Active	Increased inertia on the power system assists in limiting the post fault RoCoF caused by a large imbalance. The inertia floor of the power system has been increased from 23,000 MW.s to 28,000 MW.s which has been facilitated by the availability of two large synchronous condensers on the power system.
Battery Energy Storage Systems (BESS) charge management	Active	System wide battery charging is limited to 200 MW and the State of Charge of battery units is limited to 85% of storage capacity. These limits ensure that there is capacity for batteries to respond to high frequency events by having charging capability available. Maintaining a reduced State of Charge ensures sufficient capacity for batteries to absorb additional energy when large demand disconnects and transfers to backup systems. Similarly, the 200 MW limit ensures batteries are not already operating at maximum charging capacity, thereby preserving their ability to increase charging during such events. This response assists in rebalancing the power system post loss of demand.

[9] Frequency response on solar units was temporarily disabled in May 2026 pending completion of investigations into solar unit frequency response issues.

SNSP Limit	Active	Due to the increased system wide risk posed by the FRT issue, the SNSP (System Non-Synchronous Penetration) limit has been maintained at 75% with a decision taken not to commence a trial of operation up to 80% pending further analysis. Other renewable integration policy changes (such as a reduction in the minimum number of conventional generating units) are also on hold.
FRT Demand Curtailment	Active	Processes for EirGrid to instruct data centres to curtail their demand to ensure the 900 MW Load Rejection limit is not exceeded. A new FRT Demand Curtailment Procedure is to be introduced shortly. Activated as required to ensure system security.
Over Frequency Generation Shedding Scheme (OFGS)	Enabled	The OFGS is a 'system defence' measure that triggers the automated disconnection of wind-farms for severe over frequency events on the power system such as those that would be caused by the FRT issue. While the scheme is currently enabled (i.e. it would likely activate for a very large imbalance) the frequency settings and scope of its application are being kept under review to ensure its effectiveness.
Demand Utilisation Thresholds	Pending CRU decision	As part of EirGrid's proposed Compliance and Derogation Framework[10] associated with Grid Code modification proposal MPID345, the application of site-specific data centre non-FRT capable demand limits have been proposed to ensure that the 900 MW Load Rejection limit is not exceeded.
Coordinated restoration of data centre demand.	Under review	In the event that data centre demand reduces for a fault event, the demand is automatically restored to the grid over a period of approximately 1 minute. This restoration of demand during the post fault period can lead to further power system issues, particularly if generation has been disconnected (see OFGS reference above) in response to the initial imbalance. It may be necessary for the restoration of this demand to be coordinated with EirGrid over a longer period to avoid exacerbating the post fault recovery period.

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. This tool contains models of data centre facilities (based on data provided by data centre owners) to simulate their response to power system faults. EirGrid has continued to engage with data centre owners on the provision of representative models of their facilities including an industry information session on modelling requirements held on 19 May 2026.

It is critical that the industry supports the provision of accurate models to allow for this real-time assessment of the power system and to inform analysis of potential longer-term solutions as set out in the following section.

[10] https://cms.eirgrid.ie/sites/default/files/publications/MPID345-Grid-Code-Modification-Compliance-and-Derogation-Process-Framework.pdf

4.2 System Service and Grid Solutions

In addition to the Operational Measures outlined above, the TSOs will require enhanced grid and system service solutions 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. Further analysis of the effectiveness of additional reactive compensation has been conducted by EirGrid and is presented in section 5.

Increasing the volume of inertia and fast frequency response available can 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 commenced a process to procure a large volume of inertia via the Low Carbon Inertia Services (LCIS) procurement. Under these proposals, significant additional inertia services are expected to be procured for delivery over the coming years. 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 services[11] 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 under development and expected to go live in 2027.

Increased volumes of system services will ultimately increase costs for electricity consumers (through Demand TUoS[12] in Ireland, and the System Support Tariff in Northern Ireland[13]) and the forthcoming All-Island System Services Supplier Charge [14]. While the additional system services can be provided by other sources it is not seen as a credible alternative to addressing the issue via the proposed Grid Code FRT requirements.

The table below summarises the status of System Service / Grid solutions.

Mitigation Measure	Status	Description
Additional Inertia	Progressing	EirGrid and SONI are procuring additional inertia as part of the Low Carbon Inertia Services (LCIS) initiative. Phase 1 of this procurement has been completed with a number of synchronous condenser units due to connect to the grid before the end of 2027. Phase 2 of LCIS procurement commenced at the end of May 2026 with a target to procure a significant additional quantity of inertia.

[11] 2025-April-SOEF-Markets-FASS-Volume-Forecasting-Methodology-Recommendations-Paper.pdf
2025 April - SOEF Markets - FASS - Volume Forecasting Methodology Recommendations Paper | Soni
[12] EirGrid Statement of Charges 2023-2024
[13] SONI TUoS-Statement-of-Charges-2023-24
[14] All-Island System Services Supplier Charge

		While the inertia provided by LCIS will assist in reducing the high RoCoF seen in a FRT event, it is not seen as a credible alternative to fundamentally addressing the issue via the proposed Grid Code FRT requirements. Technical analysis of the impact of additional inertia is provided in section 5.
New Frequency Response System Services	Progressing	EirGrid and SONI have designed new frequency response System Services under the Future Arrangements for System Services (FASS) programme. These services include new 'Downward Reserves' and faster 'Fast Frequency Response' that specifically address the type of fast, high frequency scenario seen during a FRT event. These new reserve products will go-live towards the end of 2027 as part of the first Day Ahead System Services Auction (DASSA). These new frequency response services will assist in reducing the high frequency Zenith seen in a FRT event, however, they are not seen as a credible alternative to addressing the issue via the proposed Grid Code FRT requirements. Technical analysis of the impact of additional frequency response services is provided in section 5.
Additional Reactive Power Support	Not considered sufficiently beneficial	The FRT issue is primarily driven by data centre demand reductions triggered by voltage dips resulting from transmission system faults. Consideration has been given to the ability of reactive power support on the transmission system to prop up the voltage during faults to reduce the magnitude of the voltage dip and avoid triggering the resulting data centre response. The results of this analysis, which are presented in section 5, indicate that additional reactive power support is not sufficiently beneficial to avoid typical data centre demand reduction trigger points.

4.3 Enhanced Capability of Demand Facilities

EirGrid is of the view that demand facilities must be designed and operated to be able to ride-through faults on the power system and recover their demand quickly in order to reduce the magnitude of the fault related imbalance. Grid Code Modification proposal MPID345 was submitted to CRU on 1 April 2026 setting out these Fault Ride Through, Active Power Recovery and Rate of Change of Frequency requirements. 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.

Many other TSOs, and TSO representative bodies, are also seeking to develop equivalent standards. Some examples are presented in the Large Demand Facility Fault Ride Through Issue and Proposed Solutions Information Paper of November 2025[15].

[15] MPID345-Large-Demand-Facility-Fault-Ride-Through-Issue-and-Proposed-Solutions-EirGrid-and-SONI-Information-Paper-November-2025.pdf

5. Analysis of System Service / Grid Solutions

5.1 Introduction / Study Methodology

EirGrid utilises detailed dynamic power system models as part of standard operational and system planning practice to assess the impact of credible fault events on system security. These models consider the transmission system, and all large generation and demand sources connected to the transmission system, and a 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 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.

Using these modelling tools, EirGrid has undertaken an assessment of the extent to which the impacts arising from the loss of demand facility performance during and following fault events could be managed through system-based mitigation measures, in the absence of demand-side Fault Ride Through (FRT) capability. In this context, the analysis considers a scenario in which transmission-connected demand facilities do not provide the proposed FRT/APR/RoCoF performance, and the resulting system imbalance is instead addressed by the addition of significant additional volumes of inertia, delivered through synchronous condensers, and fast-acting reserve, primarily delivered through Battery Energy Storage Systems (BESS) added to the system.

The assessment/studies presented in this document reflect a significant number of studies carried out to investigate the system impact of a load-generation power imbalance caused by a fault followed by load rejection, driving the system frequency significantly above 50 Hz. The results discussed here focus on a single representative snapshot from EirGrid's real-time and look-ahead dynamic security assessment tool (LSAT), with approximately 23 GVA·s[16] of system inertia, which represents the minimum operational inertia floor. Transmission-connected data centre demand considered in this assessment was 2,000 MW, reflecting the approximate contracted level of data centre demand.

For the purposes of the assessment/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

The disturbance examined in these studies comprised the sudden load rejection of 2,300 MW, consisting of a 1,800 MW reduction in data centre demand and a 500 MW loss of EWIC export.

[16] *The operational inertia floor has since been temporarily increased to 28 GVA.s. Wk24_2026_Weekly_Operational_Constraints_Update.pdf*

5.2 Results of Dynamic Studies

Dynamic Root Mean Square (RMS) simulations were undertaken to assess the extent to which additional inertia and fast-acting reserve would be required to maintain system performance within applicable security standards following a large disturbance involving the sudden loss of demand.

The assessment/studies were carried out in three stages. The first stage assessed the inertia required to maintain RoCoF within limits. The second stage examined the additional fast-acting reserve required to maintain acceptable system frequency. The third stage considered the additional reserve required to limit the activation of Over-Frequency Generation Shedding (OFGS) to acceptable levels.

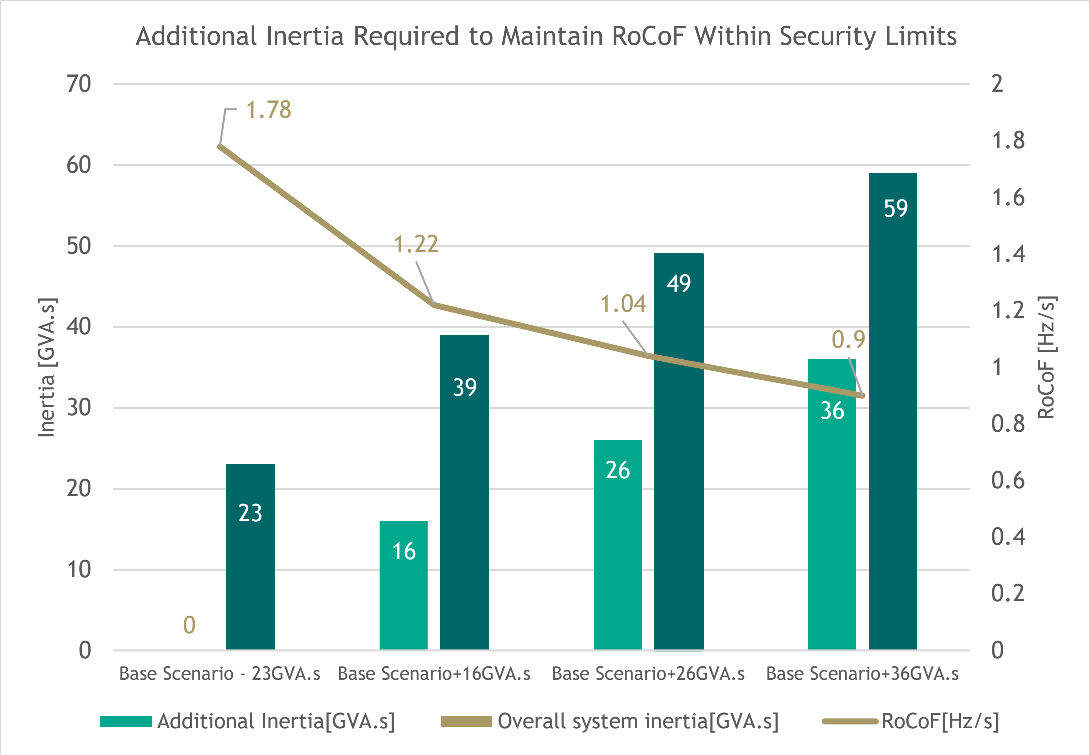
Stage 1- Additional inertia required to maintain RoCoF within limits

The first stage of the analysis examined the level of system inertia required to maintain RoCoF within the operational limit of 0.9 Hz/s following a disturbance involving the loss of approximately 2,300 MW (representing the loss of a 500 MW interconnector export plus 1,800 MW of demand loss).

The results indicate that a material increase in system inertia would be required. From a baseline level of approximately 23 GVA.s[17], inertia would need to increase to approximately 59–60 GVA·s to maintain RoCoF within the applicable limit. This represents an increase of more than 2.5 times of the All-Island power system inertia floor of 23 GVA.s considered in the study.

Achieving an inertia level of this magnitude would require the sustained operation of significantly higher levels of synchronous thermal generation, and the delivery of substantial additional volumes of low-carbon inertia services. EirGrid considers that both approaches present material challenges given the volume of increased inertia required. Increased reliance on synchronous thermal generation would further constrain the integration of renewables and be inconsistent with statutory climate objectives. Requiring increased running of thermal generation solely to provide inertia would add to generation run hours with potential knock-on risks to generation reliability and availability. This would be an unacceptable risk during a period of generation capacity adequacy challenges. While the Low Carbon Inertia Service (LCIS) is expected to deliver approximately 25 GVA·s by 2030, the additional volumes required to increase system inertia to approximately 60 GVA·s are not considered deliverable within the timeframe associated with forecast data centre demand growth.

[17] The power system inertia floor was 23 GVA.s at the time this analysis was conducted. The inertia floor has subsequently been increased to 28 GVA.s.



Stage 2 - Additional fast acting reserves required to maintain frequency zenith within limits

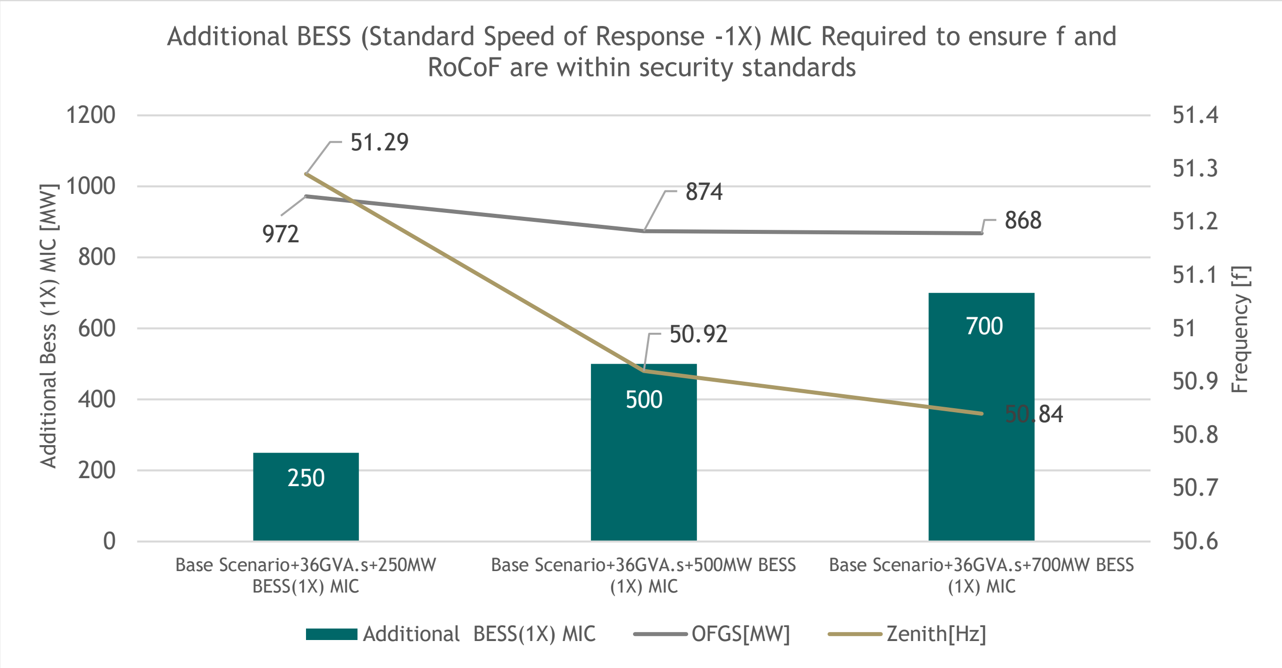
The second stage of the analysis examined the level of fast-acting reserve required to maintain system frequency zenith within acceptable limits following the disturbance, taking into account the inertia level identified in Stage 1.

As set out above, Stage 1 determined that a system inertia level of approximately 59-60 GVA·s would be required to maintain RoCoF within the applicable limits. The Stage 2 analysis was therefore undertaken on this basis and assessed the additional fast frequency response capability required to control system frequency following the disturbance.

The Stage 1 analysis demonstrates that increasing system inertia alone is not sufficient to maintain acceptable frequency performance. While a substantial increase in system inertia reduces the Rate of Change of Frequency, it does not prevent the system frequency from exceeding the frequency limits stated in Table 2. Additional fast-frequency response is required to manage the significant demand/generation imbalance caused by a fault (a 2,300 MW reduction in demand) and ensure that frequency zenith is within the limits.

The studies assessed the deployment of additional BESS units operating in charging mode to provide this fast frequency response with the additional inertia identified through the Stage 1 studies. The Stage 2 results indicate that, in addition to continued extensive use of Over Frequency Generation Shedding (OFGS is a system defence measure that disconnects generators for high frequency events) additional BESS Maximum Import Capacity (MIC) of approximately 700 MW would be required to ensure that the system frequency would not exceed 50.8 Hz.

EirGrid considers that the continued reliance on Over-Frequency Generation Shedding under this BESS scenario is unacceptable as an enduring solution. Consideration of the impact of additional BESS is considered in stage 3 below.



Stage 3 Additional BESS required to limit OFGS activation

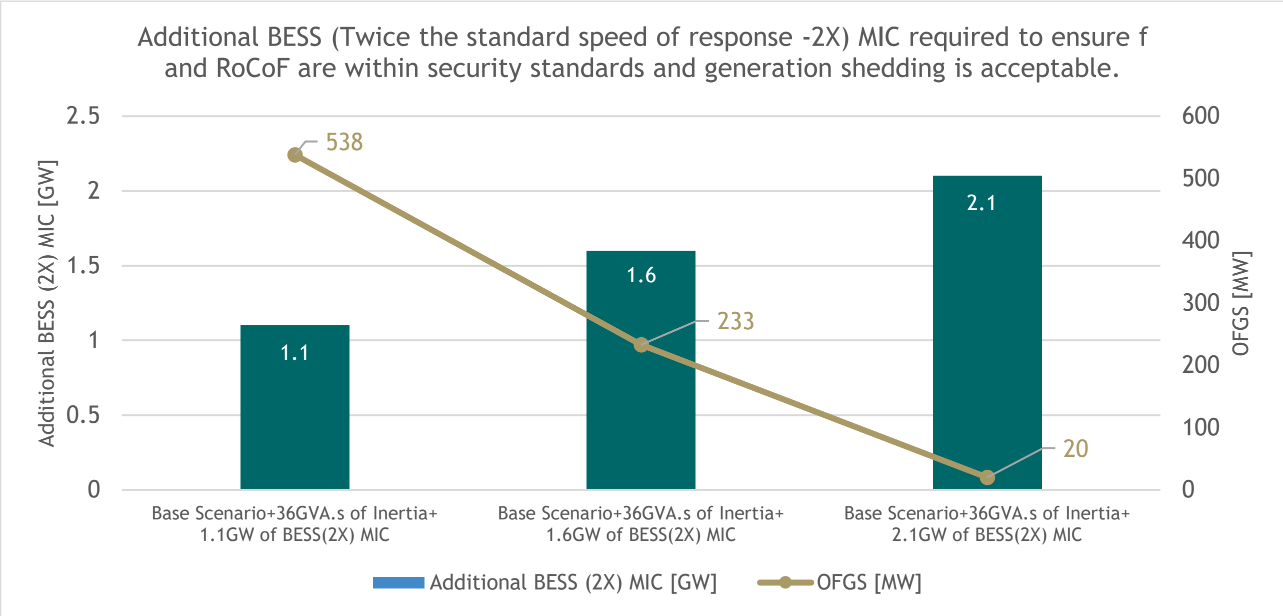
The last stage of the analysis examined the additional fast frequency response required to limit the activation of Over-Frequency Generation Shedding (OFGS), while maintaining compliance with RoCoF and frequency limits under the considered disturbance. The starting point for this analysis was the Stage 1 system inertia of 59 GVA · s. For Stage 2, we used standard settings for the additional BESS units. For Stage 3, a faster response was required to avoid significant OFGS. For these reasons, in Stage 3, we introduced additional faster BESS units at twice the rate of the standard ones.

Under these assumptions, the Stage 3 analysis assessed the extent to which further increases in fast frequency response capability would be required to avoid excessive reliance on OFGS schemes. OFGS schemes are designed to protect system stability by disconnecting generation under extreme over-frequency conditions. However, frequent or extensive activation of such schemes is unacceptable, as it introduces additional system disturbances and operational complexity. The analysis, therefore, considers the level of response required to minimise reliance on these measures. The studies assessed BESS operating in charging mode with an enhanced response characteristic equivalent to twice the standard response speed, to enable rapid absorption of excess generation.

The results indicate that materially larger volumes of BESS are required to limit OFGS activation than for frequency control alone as outlined in Stage 2. Specifically, the analysis indicates that an additional BESS Maximum Import Capacity (MIC) in the range of approximately 1.1 GW to 2.1 GW would be required. At the lower end of this range, residual OFGS activation remains, indicating that the system imbalance is not fully absorbed by the available fast frequency response. As BESS capacity increases, the level of OFGS activation reduces progressively. At approximately 2.1 GW, OFGS activation is reduced to near-zero levels, indicating that the disturbance can be managed without recourse to generation shedding.

The results demonstrate that, to maintain both frequency within acceptable limits and limit OFGS activation, a very substantial volume of fast-response BESS would be required. In addition, the requirement for BESS to operate at twice the standard response speed could result in other dynamic performance issues on the power system (a high number of interacting devices responding in very short timescales (milli-seconds) to system faults could lead to a risk of oscillatory control interactions).

EirGrid considers that the scale and performance characteristics of BESS identified in this stage represent a material increase relative to existing system capability. When considered in combination with the inertia and reserve requirements identified in Stages 1 and 2, the results indicate that reliance on system-based measures alone would necessitate a fundamental change in the design and operation of the power system.

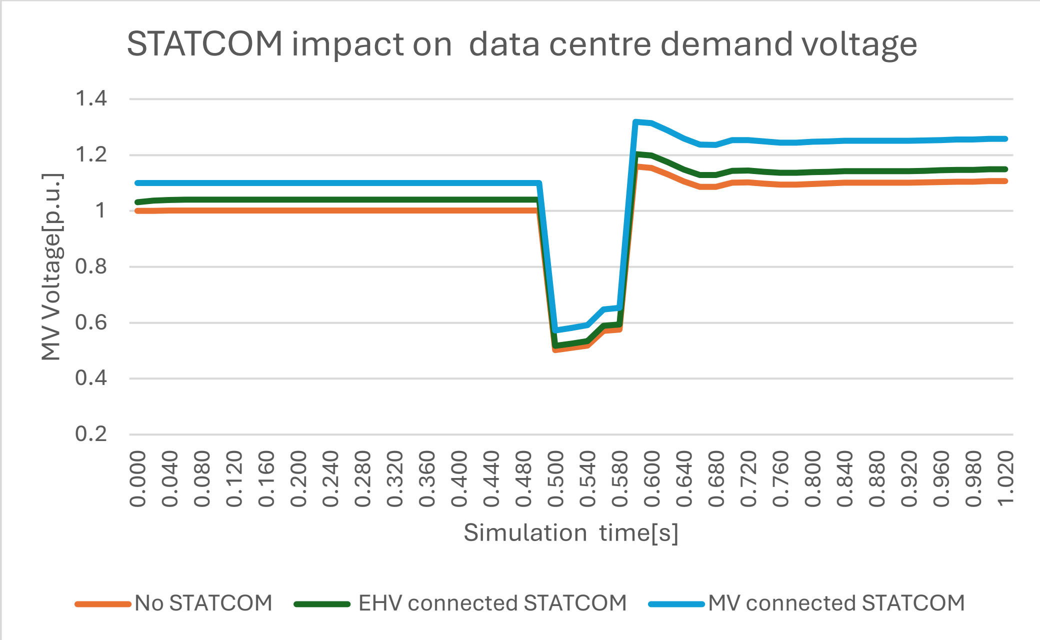


5.3 Assessment of Localised Reactive Power Support

EirGrid has undertaken additional analyses to assess the potential role of localised dynamic reactive power support in mitigating both voltage depressions and voltage recovery at transmission connected demand facilities during fault events. This assessment considers whether the installation of fast-acting reactive compensation, such as synchronous condensers or STATCOMs, at or near the point of connection of large demand facilities could improve voltage performance during faults and thereby reduce the extent of demand reduction. For the purposes of this report the results obtained through these analyses are summarised using the same LSAT snapshot as for the Stage 1 studies. A model of a STATCOM (Static Synchronous Compensator) was used for these purposes, under the following scenarios:

- No STATCOM – as is.
- EHV connected STATCOM - where the EHV bus is connected through EHV/MV transformers to the MV load point representing data centre demand.
- MV connected STATCOM - where the STATCOM is directly connected to the MV load point representing data centre demand.

The results of this analysis are presented in the figure below. The analysis examined the impact of introducing additional dynamic reactive power support at the substation for the same fault (imposed after 500 ms from the start of the simulation) as applied in the Stage 1 to Stage 3 studies. The voltage traces for all three options shown in the figure indicate that the lowest voltage recorded during the fault is between 0.5 p.u. and 0.6 p.u., with the highest voltage during the fault being 0.65 p.u. for the last option where the MV was intentionally set to a very high pre-fault value.



These findings indicate that localised reactive power support can provide an improvement in voltage performance, particularly for less severe voltage depressions, and may in some cases be sufficient to increase the voltage at the point of connection to approximately 0.8 p.u. or above. The data centre demand protection is not exclusively triggered by voltage depression; their protection can be activated by a voltage rise after the fault clearance. This is another significant challenge considering that the voltage is expected to rise due to a significant demand loss, the activation of the OFGS and consequently depletion of the reactive power support and significant perturbation of the grid flows.

For more severe fault events resulting in deeper voltage dips, the effectiveness of such measures is definitely limited. The analysis demonstrates that even with substantial volumes of reactive power support, it would not be feasible to raise the voltage during these events to levels sufficient to reliably prevent demand reduction. On this basis, localised reactive compensation is not considered to provide a credible standalone alternative to demand-side FRT and APR capability.

In addition, any such solution would require a significant placement of these devices across Dublin which is already highly congested with insufficient space and connection capacity for the level of additional compensation devices indicated by this analysis. Voltage control and operational coordination issues would also arise with a high number of interacting devices responding in very short timescales (milli-seconds) to system faults leading to a risk of oscillatory control interactions. The transmission network in Dublin is also constrained from a fault level perspective which would limit the capability of the network to accommodate additional devices that increased these fault levels.

5.4 Summary of Dynamic Simulation Study Results

The dynamic simulations undertaken in this assessment examined the extent to which additional inertia, fast-acting reserves and reactive power capability would be required to maintain RoCoF, system frequency and generation shedding within acceptable operational limits in the absence of demand-side Fault Ride Through capability.

The analysis demonstrates that managing the disturbance considered would require a combination of increased system inertia and volumes of fast-response BESS charging capability that are multiples of the current power system capability. In particular, the results indicate that an inertia level of approximately 59–60 GVA·s would be required to maintain RoCoF within applicable limits. Even at this elevated level, additional fast-acting reserve is required to control system frequency, with further increases necessary to limit reliance on Over-Frequency Generation Shedding mechanisms. Reactive power support is shown to be ineffective in addressing the issue.

The scale of BESS deployment required to achieve these outcomes is significant when considered relative to existing system capability, and would also require performance characteristics beyond current standard operational practices. In combination, the inertia and reserve requirements identified represent a material increase relative to current system capability and would introduce unacceptable levels of complexity and risk to the operation of the All-Island power system threatening security of supply for all electricity consumers.

In particular, the magnitude and speed of the required BESS response would have implications for the dynamic response of the power system, including changes to power flows and voltage behaviour, as well as potential interactions between multiple fast-acting devices. There would be an unacceptable risk of control system interactions leading to power system oscillations that would risk the security of the entire power system.

The scale of deployment would also present challenges for transmission network development and for the integration of such capacity in a coordinated and secure manner. This approach would tie-up grid capacity and connections that would significantly inhibit the ability of the grid to accommodate demand growth and new demand connections. In addition, reserving BESS capacity for system security purposes would limit its availability for market participation and may give rise to associated costs and operational constraints.

5.5 Comparison with other power systems

EirGrid has considered the scale of the disturbance assessed in this analysis relative to that experienced in other power systems, regarding system inertia levels and the magnitude of credible generation and load rejection events.

The ratio of potential generation or load rejection to peak system demand is a key indicator of the relative scale of the balancing challenge, and the contrast between the all-island system and other jurisdictions is material to the conclusions of this assessment.

TSO (Jurisdiction)	Peak Demand [GW]	Inertia Floor [GVA.s]	Ratio Inertia Floor to Peak Demand[18]	Secured Imbalance (maximum generation or load imbalance) [MW]	Ratio Max. Imbalance to Peak Demand
AEMO (Australia)	10	36	3.6	Generation rejection: 500 MW Victoria 600 MW Queensland Load rejection is smaller than above	0.06
NESO (GB)	45	120	2.66	1400 MW - Generation rejection Load rejection is smaller than above	0.03
ERCOT (Texas)	86	100	1.16	2600 MW (Max demand loss limit)	0.03
EirGrid/ SONI (Ireland /N.Ireland)	7.5	23	3.06	1. Current: 900 MW Load Rejection[19] 2. Planned: 734 MW HVDC Interconnector. 3. Potential: 2300 MW (1800 MW data centre loss + 500 MW EWIC Export)	1. 0.12 2. 0.10 3. 0.31

The comparison shows that the ratio of imbalance to peak demand is already relatively high for the Ireland / N. Ireland power system than those typically considered in other jurisdictions. The ratio of potential demand loss to peak demand for the EirGrid system could be approximately 0.31 if FRT requirements at demand facilities were not implemented. This compares with values generally in the range of 0.03 to 0.06 in systems such as ERCOT, Great Britain and AEMO. Ireland would be an extreme outlier in having imbalance/peak demand ratios 5 to 10 times larger than the other power system with data centres on their system.

For example, in ERCOT, an acceptable level of demand loss for an 86 GW system is approximately 2,600 MW, corresponding to an imbalance/peak demand ratio of around 0.03. By comparison for Ireland / N.Ireland, the disturbance examined in this analysis is approximately 2,300 MW (based on demand facilities not having FRT capability) on a system with a peak demand of approximately 7.5 GW, giving a ratio that is an order of magnitude higher.

It should be noted that these ratios are with respect to peak system demand so would typically be 2 to 3 times greater for minimum power system demand periods.

This difference is material to the assessment of alternative mitigation measures. It demonstrates that, if FRT capability is not delivered at demand facilities, the all-island system would be exposed to disturbances that are significantly larger, relative to system size, than those typically considered in other power systems.

[18] This ratio is calculated as the system inertia floor (in GVA.s) divided by the system peak demand (in GW)
[19] As published in the latest Weekly Operational Constraint Update: General Publications | SEMO

5.6 Studies on Dynamic Reactive Power Support and Load Loss Mitigation conducted by another TSO

Studies have been presented by ERCOT (the System Operator in Texas) on the effectiveness of grid and system service solutions in mitigating loss of load from Large Electronic Loads. In those studies, a threshold of approximately 2,600 MW was applied in the ERCOT studies as the maximum system-wide load loss that could be accommodated under the study conditions[20].

The transmission-based mitigation measures assessed in the ERCOT studies included the addition of five new synchronous condensers providing 1.75 GVAr, together with two E-STATCOM deployment scenarios of 30.4 GVAr and 77.4 GVAr respectively. The results indicate that additional dynamic reactive power support can reduce the magnitude of load loss for some representative fault events and, in a number of cases, reduce the residual loss below the 2,600 MW threshold. However, the benefit was not uniform across the critical events assessed, and for some severe contingencies the residual loss remained above the threshold even with the larger 77.4 GVAr E-STATCOM deployment.

The ERCOT study concluded that the transmission-based measures assessed, including synchronous condensers and E-STATCOMs, had a varying impact on the magnitude of load loss and were not effective for most of the critical events examined. The most effective outcome was associated with enhancement of load-side fault ride-through capability of data centres. The study also noted that, although transmission strengthening may improve network strength, this does not prevent significant voltage dips from arising at buses electrically close to the fault location immediately following the fault.

[20] https://www.ercot.com/files/docs/2025/10/21/Status-Update_Effectiveness-of-Transmission-Upgrades-Load-Loss-LLWG-2025-10-24.pdf

5.7 Conclusions regarding consideration of System Service / Grid Solution Alternatives

EirGrid does not consider that the additional inertia, reserve or reactive power measures considered in this analysis offer a credible technical or practically deliverable alternative to the implementation of FRT/APR/RoCoF requirements at demand facilities.

The assessment has focused on frequency and RoCoF performance using RMS dynamic simulations. While the modelling captures the principal system dynamics associated with the disturbance, other factors, including voltage stability, control interactions, oscillations and wider system effects, are represented only to the extent permitted by the modelling framework. In addition, the scalability of the identified system-based solution beyond the demand level considered has not been assessed, and the associated challenges would be expected to increase at higher levels of demand.

EirGrid considers that, while inertia and fast frequency response remain essential components of system stability, their use as a substitute for demand-side Fault Ride Through and Active Power Recovery capability would not provide a technically feasible solution at the scale required. Addressing the issue at source, by ensuring that demand facilities remain connected and recover in a controlled manner during and following fault events, more directly reduces the magnitude of system disturbances and provides the only feasible and acceptable basis for maintaining operational security.

Addressing the issue primarily through grid-based measures would represent an unacceptable departure from established power system planning and operational practices. It would require the all-island system to be capable of accommodating disturbances of a scale that have never been seen in other comparable power systems and would introduce an unacceptable level of risk to system security in addition to increased operational complexity by international power system standards.

The conclusion that the FRT issue cannot be resolved solely by System Service / Grid solutions is reflected in the development of equivalent FRT requirements for demand facilities progressing in multiple other jurisdictions. EirGrid is not aware of any jurisdiction solely relying on System Service / Grid Solutions to resolve significant fault ride through challenges, or manage large imbalances, such as those that exist on the All-Island power system. The development of demand-side performance requirements is being progressed internationally, and ENTSO-E has recommended that TSOs advance national technical requirements to support system stability. EirGrid considers that the approach proposed under MPID345 is consistent with this direction.

This analysis concludes that System Service / Grid solutions alone do not offer credible alternatives to the implementation of FRT/APR/RoCoF capability at demand facilities. Attempting to secure for instantaneous demand reductions of the magnitude modelled would introduce an unacceptable level of complexity and risk to the security of the All-Island power system and threaten security of supply for all electricity consumers. This approach would also tie-up grid capacity and connections that would significantly inhibit the ability of the grid to accommodate demand growth and new demand connections.

It remains critical that implementation of Grid Code Modification proposal MPID345, supported by the associated Compliance and Derogation framework and the implementation of solutions by customers, are progressed as quickly as possible to manage the increasing risk to the security of the All-Island power system and reduce the operational and commercial impacts of the mitigation measures being taken on customers.