An Coimisiún um Rialáil Fóntais
Commission for Regulation of Utilities

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Ireland's 2026 Flexibility Needs Assessment

Report

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CRU Strategic Plan 2025-27

Vision, Purpose, and Values

OUR VISION:

Resilient, efficient, sustainable, and safe energy and water services for Ireland.

OUR PURPOSE:

We actively serve the public interest by regulating the provision of energy and water to Irish homes and businesses, while supporting the transformation to net zero.

OUR VALUES:

- Integrity
- Professionalism
- Openness
- Accountability

Executive Summary

This report presents Ireland's first National Flexibility Needs Assessment (FNA), prepared in accordance with Article 19e of Regulation (EU) 2019/943, as amended by the Electricity Market Design Reform (Regulation (EU) 2024/1747)[1], and the ACER Flexibility Needs Assessment Methodology (the "ACER Methodology")[2]. It assesses Ireland's flexibility needs across the electricity system and networks for 2028 and 2030, sets out options to meet them, and identifies the key market, regulatory and operational barriers to the deliverability of flexibility.

In completing this assessment, the CRU recognises that flexibility can be provided by a wide range of sources including demand-side resources, energy storage, flexible generation and distributed energy resources capable of adjusting generation or consumption and enabled through a range of policy, regulatory, market and operational arrangements. These sources may be facilitated or incentivised in different ways, including through market arrangements and participation, flexibility products, connection arrangements and operational coordination.

Flexibility resources may form part of the response to the needs identified in this assessment, particularly where they can address localised or time-bound needs. Market, operational and network measures will also be important in reducing the underlying level of need. It may not be economic or efficient to meet all identified needs in full, and some residual renewable dispatch down, or station congestion on the distribution system, may remain where this reflects an efficient market or operational outcome. The identification of flexibility needs in this report should therefore not be interpreted as prescribing a specific technology, commercial model or procurement route to meet those needs, or as an indication that the identified needs must be met in their entirety.

This is the first application of the ACER FNA framework in Ireland. Although all Member States will apply a common methodology, national assessments may differ in their analytical approaches and presentation, reflecting national circumstances, available data and existing modelling arrangements.

The FNA report should be considered alongside Ireland's wider work to increase electricity system flexibility, including through the National Energy Demand Strategy, and should be read alongside the associated Demand Flexibility Forecast Report 2026 when it is published.

Approach to flexibility needs assessment

The flexibility needs analysis has been undertaken jointly by EirGrid and ESB Networks, with coordination and input by the CRU, following the ACER Methodology structure. The CRU has

[1] Regulation - EU - 2024/1747 - EN - EUR-Lex
[2] Flexibility needs assessment methodology 2025

also coordinated with the Utility Regulator in Northern Ireland in the development of the FNA, as have the respective System Operators. This FNA covers the flexibility needs for Ireland, while the Utility Regulator has undertaken the FNA for Northern Ireland. The CRU would like to thank its colleagues in the Utility Regulator for their support in preparing the FNA and thank the System Operators for their work on the analysis and modelling required by the FNA.

System level analysis: economic dispatch modelling to assess flexibility needs associated with increasing renewable generation. Flexibility needs are identified through analysis of dispatch outcomes, including surplus renewable generation and curtailment of renewable generation, across a range of scenarios and weather conditions. The system level analysis considers flexibility requirements related to renewable integration, short-term operational needs and ramping, as required by the ACER Methodology.

Transmission level analysis: analysis of constraint-related dispatch down outputs from a distinct modelling process (using the same modelling which is used for the connection offer process, the ECP process) to identify the level and characteristics of constraint-driven dispatch down.

Distribution level analysis: a location-specific approach to identify stations where forecast demand is expected to exceed available capacity net of planned reinforcement.

Interpretation of results:

The report recognises methodological and practical challenges aligning the ACER Methodology with existing modelling approaches and SEM-specific arrangements. These considerations should be taken into account when interpreting the identified flexibility needs. The purpose of the FNA is to assess the flexibility needed to support renewable integration and respond to system and network needs under the scenarios and assumptions considered. This is distinct from national and European resource adequacy assessments, which consider whether sufficient capacity is available to maintain security of supply and meet electricity demand. The findings of this assessment should therefore be interpreted as flexibility needs, rather than as an assessment of resource adequacy or security of supply.

Identified flexibility needs

System level analysis: Significant RES integration flexibility needs have been identified which increase with higher levels of renewable generation capacity. The analysis shows that dispatch down is driven by a combination of surplus renewable generation, curtailment and operational constraints (as described in the ECP 2.5 model assumptions)[3].

Transmission network level: Congestion is the predominant driver of dispatch down in 2028 while by 2030 anticipated network development reduces the impact of congestion on the network.

[3] https://cms.eirgrid.ie/sites/default/files/publications/ECP-2.5-Assumptions-Document-Final-Update.pdf

Distribution network level: Flexibility needs identified are significant in local terms, with material requirements concentrated in specific zones and stations (e.g. Dublin). The total identified flexibility needs (upward flexibility[4]) are: 2028: ~234 MW and ~58 GWh, 2030: ~226 MW and ~53 GWh.

Options to meet identified flexibility needs

A range of approaches will be required to address the identified flexibility needs. This could include both short-duration and longer-duration flexibility resources and different flexibility technologies, as well as targeted market, operational and network measures that will target reducing the level of need or support more efficient system operation.

At the system level, while additional flexibility can help to reduce surplus and curtailment (with different flexibility durations providing different benefits), completely eliminating RES dispatch down through additional flexible capacity alone would require very large volumes of resource. Some level of residual RES dispatch down should therefore be expected, alongside continued consideration of other measures which could reduce the level of need.

At network level, reinforcement and operational improvements remain important drivers for reducing constraints and curtailment. For example, the analysis indicates that TSO operational measures which reduce the need to keep minimum levels of non-renewable generation online could materially reduce RES dispatch down. **This reinforces that flexibility resources may be part of the response, particularly where they can address localised or time-bound constraints, but that market, operational and network measures will also be important in reducing the underlying level of need**.

At distribution network level, different flexibility solutions may be suited to the different types of local distribution constraints, with demand response and shorter-duration storage identified as suitable options for predictable, time-bound congestion events. Future network reinforcement is also expected to resolve some identified needs, with flexibility potentially complementing or providing an interim solution ahead of its delivery.

Market design and regulatory barriers

While the quantified needs reflect a short-term view, the consideration of barriers reflects a longer-term perspective, as flexibility needs are expected to increase with renewable penetration and these barriers to become more material over time if not addressed. While a number of initiatives are already underway to support the development of flexibility including reforms to wholesale market arrangements, new flexibility products, reductions in operational constraints, and programmes to improve system coordination, this report highlights a number of barriers to the deployment of flexibility including:

[4] Upward flexibility need is defined (within the ACER Methodology) as a need whose solution requires either increasing injection into the network or decreasing demand from the network. Downward flexibility is defined as a need whose solution requires either decreasing injection into the network or increasing demand from the network.

- Economic signals and revenue: improvements in the clarity and reliability of economic signals and further enabling arrangements could facilitate more efficient participation and investment from flexibility providers, particularly for smaller and emerging resources. A key cross-cutting challenge relates to the ability of flexibility providers to generate viable and stable revenue streams, although progress is being made to enable revenue stacking where appropriate. Better alignment between market signals and physical system needs, including through improved locational signals, could enable flexible resources to provide their full value and contribute to more efficient market outcomes.
- Grid access: available network capacity and connection timeframes can act as a binding constraint on connecting and operating flexible resources — even where those resources could otherwise help alleviate the same constraints.
- TSO–DSO coordination: the further development of coordinated operating arrangements, clear roles and responsibilities, and standardised processes for information exchange is needed for flexibility to deliver value across both system-wide and local needs, with joint TSO–DSO operational frameworks expected to play an important role in addressing a number of challenges.

Key Findings

- System and transmission flexibility needs centre on managing surplus renewable generation, distribution flexibility needs stem from localised capacity constraints
- Flexibility is expected to complement, rather than replace, network reinforcement
- Flexibility needs may be met through explicit flexibility products and more efficient market arrangements that strengthen signals and enable flexible resources to respond to system needs. It is not likely to be economic to meet all the identified needs, and some residual renewable dispatch down is expected to remain.
- Market, regulatory and operational barriers to flexibility exist, although good progress is already being made to enable and support flexibility.
- There were challenges associated with applying the ACER methodology using existing modelling frameworks and aligning European methodology requirements with SEM-specific operational arrangements and processes. These will be considered further to make potential improvements for future iterations of the FNA.

Next Steps

As required by Regulation (EU) 2019/943 (as amended by Regulation (EU) 2024/1747), Ireland is required to set an indicative national objective for non-fossil flexibility in 2027. This FNA will form part of the evidence base considered in setting that objective. The CRU expects to continue working with EirGrid and ESB Networks to further develop the supporting analysis and evidence base, and to support the Department of Climate, Energy and the Environment in setting the objective.

The findings of the FNA may also inform future policy, regulatory, market and procurement-related decisions. Future work will consider a range of approaches to addressing the identified flexibility needs, including flexibility products, market and operational reforms, network development and other measures which may reduce, and/or meet the underlying need. EirGrid and ESB Networks are expected to consider the findings in future work on potential approaches to enabling and deploying flexibility where needed. The CRU, EirGrid and ESB Networks will also work to better understand and, where appropriate, address the key barriers and identify areas for improvements for future FNA iterations. Work will also continue on related policy, market and regulatory workstreams.

Regulation (EU) 2019/943 (as amended by Regulation (EU) 2024/1747) requires an updated FNA at least every two years. Work on the next iteration is expected to commence during 2027 and will likely consider longer-term requirements, additional target years (i.e. a 5-10 year horizon) and further refinements to the data and modelling approaches.

Public/ Customer Impact Statement

Ireland's electricity system is undergoing significant change as increasing volumes of renewable generation are integrated onto the electricity system. Ensuring that the power system can operate securely, efficiently and cost-effectively, both as the system evolves and in the longer term, will require increasing levels of flexibility across the electricity system. As electricity demand rises, driven by the electrification of heat and transport, flexibility will play an increasingly important role in meeting this demand sustainably. Furthermore, flexibility also helps in bridging the gap between immediate network needs and longer-term, multi-year network reinforcement projects.

The Flexibility Needs Assessment does not in itself introduce new obligations, charges, market arrangements or investment decisions. Rather, it provides an evidence-based assessment of where flexibility needs may emerge in the future and identifies potential regulatory, market and operational barriers which may affect the ability of flexibility resources to respond to those needs. The findings are intended to inform future policy, regulatory and industry decision-making.

Greater understanding of future flexibility needs, and of the barriers that could limit the deployment and participation of flexibility resources, can help support the efficient integration of renewable generation, the secure operation of the electricity system, and the delivery of value for customers. By providing a structured assessment of future needs and the factors which may affect their delivery, the FNA supports the CRU, government, system operators and market participants in identifying appropriate actions to support Ireland's renewable electricity transition and the development of a secure, sustainable and efficient electricity system for the benefit of customers and the wider public. Flexibility resources may help address localised or time-bound needs, while market, operational and network measures may reduce the underlying need. The assessment does not prescribe a specific technology, commercial model or procurement route.

Report Structure

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Glossary of Terms and Abbreviations

Abbreviation or Term	Definition or Meaning
ACER	European Union Agency for the Cooperation of Energy Regulators
ADMD	After Diversity Maximum Demand
AIRAA	All-Island Resource Adequacy Assessment
APIs	Application Programming Interfaces
BESS	Battery Energy Storage System
BTM	Behind the Meter
B/B	Busbar
CAPEX	Capital Expenditure
CBA	Cost Benefit Analysis
CRM	Capacity Remuneration Mechanism
CRU	Commission for Regulation of Utilities
DFP	Demand Flexibility Product
DMDs	Demand Measurement Devices
DNDP	Distribution Network Development Plan
DR	Demand Response
DSF	Demand Side Flexibility
DSO	Distribution System Operator

DSU	Demand Side Unit
ECP	Enduring Connection Policy
ED	Economic Dispatch
END	Energy Not Delivered
ENS	Energy Not Served
ENTSO-E	European Network of Transmission System Operators for Electricity
ERAA	European Resource Adequacy Assessment
ESB	Electricity Supply Board
ESBN	Electricity Supply Board Networks
EU	European Union
EV	Electric Vehicle
EVA	Economic Viability Assessment
FASS	Future Arrangements for System Services
FIS	Flexibility Information System
FNA	Flexibility Needs Assessment
FSA	Flexibility Service Asset
FSP	Flexibility Service Provider
FTM	Front of the Meter
GB	Great Britain
GDPR	General Data Protection Regulation
GWh	Gigawatt-hour

HV	High Voltage
IE	Ireland
JSOP	Joint System Operator Programme
kV	Kilovolt
kVa	Kilovolt-Ampere
kW	Kilowatt
LCT	Low Carbon Technology
LDF	Long Duration Flexibility
LDES	Long Duration Energy Storage
LEUs	Large Energy Users
LV	Low Voltage
MEC	Maximum Export Capacity
MIC	Maximum Import Capacity
MPRN	Meter Point Reference Number
MTU	Market Time Unit
MV	Medium Voltage
MVA	Mega Volt-Ampere
MW / MWh	Megawatt / Megawatt-hour
NCDR	Network Code for Demand Response
NECP	National Energy and Climate Plan
NEDS	National Energy Demand Strategy
NNLC	National Network, Local Connections

NI	Northern Ireland
NRAA	National Resource Adequacy Assessment
OPEX	Operational Expenditure
PR5 / PR6	Price Review 5 / 6
QTP	Qualification Trial Process
RES	Renewable Energy Sources
RES-E	Renewable Energy Sources for Electricity
RMT	Ramping Margin Tool
RoCoF	Rate of Change of Frequency
SCADA	Supervisory Control and Data Acquisition
SDF	Short Duration Flexibility
SDP	Scheduling and Dispatch Programme
SEAI	Sustainable Energy Authority of Ireland
SEM	Single Electricity Market
SI	Statutory Instrument
SLR	Special Load Reading
SME	Small and Medium Enterprise
SNSP	System Non-Synchronous Penetration
SONI	System Operator for Northern Ireland
SPGs / SPUs	Service Providing Groups / Units
STFlex	Short Term Flexibility
TSO	Transmission System Operator

TSSPS	Transmission System Security and Planning Standards
TYNDP	Ten-Year Network Development Plan
UR	Utility Regulator
VRES	Variable Renewable Energy Sources
WAM	With Additional Measures
WS	Weather Scenarios
XLEUs	Extra Large Energy Users

Term	Definition
After Diversity Maximum Demand (ADMD)	**Accounts for the coincident peak load a network is likely to experience over its lifetime.**
All-Island Resource Adequacy Assessment Report	**Report that evaluates the electricity supply and demand across Ireland and Northern Ireland over the next decade to ensure secure, reliable and sustainable energy.**
Bulk Supply Point	**A transmission station that feeds into the sub-transmission system usually at 38kV.**
Capacity Factor (for wind/solar)	**Used to calculate the average output of a renewable generator. The average capacity factor for wind and solar used by ESBN for their analysis is 35% and 13.3% respectively.**
Capital Works Programme	**Planned investment projects carried out to develop, upgrade, or expand the electricity network infrastructure. This includes projects identified in PR5, PR6, accelerated project list and asset replacement list.**

Cleansed SCADA Peak	**The peak that is obtained after historical data from SCADA systems is subjected to a cleansing methodology in order to normalize the load project against any peaks or abnormal loading behaviour.**
Climate Year	**A climatic year or weather scenario simulated within ERAA or NRAA. For the purpose of the FNA methodology, the terms 'climate year' and 'weather scenario' are given the same meaning;**
Confidential Information	**Non-aggregated information and information restricted under national law, trade secrets and relevant confidentiality agreements, exchanged for the purpose of the FNA report.**
Connection Agreement	**An agreement between the DSO and each User setting out terms relating to a connection with the distribution system.**
Customer BTM storage	**Collections of customer assets (stationary batteries, EVs and fleets), typically aggregated by an intermediary to provide a single contracted product.**
Cycle Period	**Cycle period in Sincal is defined as the time duration for the power flow assessment.**
D-1	**The latest forecast reported at, in local time of the bidding zone, 12:00 the day before real-time observation in the same bidding zone.**
Daily Timeframe	**A timeframe for the characterisation of flexibility needs which occur at the level of the single day of the year. Depending on the specific indicator, daily values can be further characterised (e.g. cumulated, averaged, etc.) to provide statistical insight on flexibility needs.**
Demand	**The total instantaneous electricity consumption observed in the transmission and distribution systems, including the network losses.**
Demand Side Unit (DSU)	**An individual Demand Reduction site or Aggregated Demand Site with a Demand Reduction Capability of at least 4MW. The Demand Side Unit shall be subject to Central Dispatch.**

Demand Capacity Headroom Report	**This workbook provides indicative "headroom" capacity available for new demand connections at existing 110kV and 38kV substations. Forecasts are produced for every year up to 2030, and then for every five years after that out to 2050.**
Demand Diversity Factor	**Factor determined by ESB networks to determine the after diversity maximum demand for a customer which can be utilised to evaluate the network limitations for its connection to the DSO network.**
Designated Authority or Entity	**The regulatory authority or another authority or entity designated by a Member State to receive the data and analysis submitted by TSOs and DSOs pursuant to Article 19e(3) and adopt the FNA report pursuant to Article 19e(1) of the Electricity Regulation (as amended by Regulation (EU) 2024/1747).**
Digital and Operational Measures	**Software, telemetry, market stacking platforms and network control techniques that improve utilisation of existing assets and enable flexible dispatch.**
Dispatchable Assets	**Assets (as individual units or aggregated) which are controllable by market participants or system operators to manage system or network needs.**
Distribution Network Development Plan (DNDP)	**Outlines the infrastructure CAPEX reinforcement plans and also indicates areas of the network where flexibility services will be required.**
Dispatchable local generation	**Dispatchable generation located on the distribution network (e.g., gas engines, bioenergy, reciprocating engines) used to relieve local congestion. Hybrids (dynamic sharing of MEC) offers a way to achieve RES dispatchability by combining it with storage.**
Downwards Flexibility	**The needs whose solution requires either decreasing injection into the network or increasing demand from the network.**
Economic dispatch (ED)	**A mathematical optimisation model as described in Article 7 of the ERAA methodology.**
Economic Viability Assessment (EVA)	**A model assessing the profitability of capacity resources, informing decisions on retirement, mothballing and re-entry,**

	renewal/prolongation and new-build of a capacity resource as described in Article 6 of the ERAA methodology.
End User	**A connected customer represented by an MPRN, with an agreed Maximum Import Capacity (MIC)/Maximum Export Capacity (MEC), who consumes/generates electricity from/for the distribution network and is subject to DUoS charges.**
Energy Not Delivered (END)	**The energy which is not supplied due to network constraints.**
Energy Not Served (ENS)	**The energy which is not supplied due to insufficient capacity resources to meet the demand.**
European Resource Adequacy Assessment (ERAA)	**The most recent European resource adequacy assessment conducted by ENTSO-E pursuant to Article 23 and approved by ACER pursuant to Article 27 of the Electricity Regulation.**
ERAA Methodology	**The methodology for the European resource adequacy assessment developed by ENTSO-E pursuant to Article 23(3) of the Electricity Regulation.**
Fast Flexibility	**The capacity able to react to aggregated D-1 or shorter error variations (15 to 60 minutes before real-time).**
Firm Capacity	**The capacity that a HV station can sustain over a prolonged period under both normal feeding operation and during an outage due to a fault or maintenance of a transformer at a station.**
Flexible Connection Agreement	**A set of agreed conditions for connecting electrical capacity to the grid that includes conditions to limit and control the electricity injection to and withdrawal from the transmission network or distribution network.**
Flexibility Information System	**A digital platform used by power grids and distribution system operators to register participants, manage distributed energy resources, and facilitate the trading of grid flexibility services.**
Flexibility Service	**The provision of flexibility products, under a set of agreed terms, which give the System Operator the ability to manage**

	the load at a specific point of the Network at certain points in time.
Flexibility Service Asset	**A single standalone DER asset and/or installation capable of providing a flexibility service.**
Flexibility Service Provider	**A legal entity which owns or has rights to operate Flexible Service Unit(s) consisting of Flexible Service Asset(s).**
FNA Report	**A report on the estimated flexibility needs for a period of at least the next 5 to 10 years adopted at national level pursuant to Article 19e(1) of the Electricity Regulation (as amended by Regulation (EU) 2024/1747).**
Hourly Timeframe	**A timeframe for the characterisation of flexibility needs which occur at the level of the single hour of the year. Depending on the specific indicator, hourly values can be further characterised (e.g. cumulated, averaged, etc.) to provide statistical insight on flexibility needs.**
Implicit Demand Response and Smart Tariffs	**Price signals or time varying tariffs that incentivise customers to change consumption without direct dispatch.**
Installed Capacity	**Each station on the distribution system has installed capacity which is established by virtue of the nameplate rating on the transformer.**
Interconnection and cross-border flexibility	**Capacity and energy flows across transmission interconnectors that change system level supply and demand patterns.**
Local Service	**Energy or capacity procured by a TSO or DSO to solve congestion or voltage issues they have identified in their systems.**
Local Maximum Value	**Maximum flexibility (expressed in MW) needed to solve a congestion or voltage issue on a given asset during a given time block.**
Long-duration and seasonal storage	**Technologies designed to store energy for many hours to months (e.g., pumped hydro, hydrogen, thermal seasonal stores).**

Maximum Export Capacity (MEC)	**The maximum power that a customer is permitted to export via their ESB Networks electricity connection.**
Maximum Import Capacity (MIC)	**The amount of electricity a customer is expected to use. It is calculated by adding up all the individual loads of the different equipment using electricity and applying a diversity factor.**
Minimum Load	**For the purpose of the Downward Flexibility Analysis based on Pilot 4, the estimated minimum load for a station is taken as 20% of the yearly max as a proxy for the summer valley load for that year.**
Network Flexibility Needs	**The flexibility needed to adjust for grid availability, by means of preventing or solving congestion or voltage issues, across relevant timeframe.**
National Energy and Climate Plan (NECP)	**An integrated national energy and climate plan pursuant to Regulation (EU) 2018/1999.**
Network Congestion	**A situation in which the electric current flow through a physical asset (e.g. transformer) exceeds the capacity of that asset.**
Non-Dispatchable Generation	**Assets which are constrained in controllability of injections following weather or other conditions such as wind, solar and run-of-river hydro generation.**
National Resource Adequacy Assessment (NRAA)	**The most recent national resource adequacy assessment pursuant to Article 24 of the Electricity Regulation. If an NRAA is subject to ACER's opinion pursuant to Article 24(3) of the Electricity Regulation, it shall only be considered for the purposes of the FNA methodology once it is amended in accordance with ACER’s opinion or accompanied by a report detailing the reasons for not fully incorporating ACER's opinion.**
Non-Firm Capacity	**The total capacity that could be provided at a station taking account of load transfer arrangements in place to transfer demand to adjacent stations, or flexible load at the station that can be used to reduce demand within the required timeframe.**

Non-Wire Alternative	**A solution to network congestion that does not rely on capital reinforcement.**
PR6	**Every 5 years ESB Networks make a submission to the Commission for the Regulation of Utilities (CRU) to outline the expenditure needs on the distribution network. The PR6 period runs from 2026 to 2030. The CRU issued the determination for the PR6 period on 16th December 2025.**
Planner Zones	**The distribution network of Ireland is divided into 27 planner zones. These planner zones are divided electrically based on multiple bulk supply points (substations that provide exchange of energy between transmission and distribution system) in a specific area.**
Ramping Needs	**The needs associated with variations of the residual load assuming perfect forecast conditions.**
Residual Load	**The total demand minus non-dispatchable generation (as individual units or as aggregated units), such as from wind or solar as well as generation, subject to must run conditions per market time unit.**
RES Curtailment	**Limiting the generation or transmission of renewable power for system operational reasons or grid-capacity reasons.**
RES Integration Needs	**The quantity of flexibility required for the Member State to achieve its annual RES integration target.**
RES Integration Target	**The maximum RES curtailment amount or share compatible with the RES target for the Member State. It is expressed either as a maximum RES curtailment in absolute terms, or as a maximum RES curtailment in relative terms to the total RES generation or to the total electricity demand, or symmetrically as the minimum effectively integrated (i.e., non-curtailed) RES generation in absolute terms or in relative terms to the total RES generation or to the total electricity demand.**
RES Target	**The national target for RES in the electricity sector of the most recent NECP or from another relevant official national document consistent with the most recent NECP. It is either expressed as a RES volume in absolute terms or as a share**

	of RES production in relative terms to the total electricity demand.
Seasonal Timeframe	**A timeframe for the characterisation of flexibility needs which occur at the level of the single month of the year. Depending on the specific indicator, monthly values can be further characterised (e.g. cumulated, averaged, etc.) to provide statistical insight on flexibility needs.**
Short-Term Flexibility Needs	**Needs associated with unexpected variations of the residual load such as forced outage of assets during the intra-day or balancing timeframe.**
Slow Flexibility	**The capacity able to react to aggregated D-1 or shorter horizons forecast error (60 minutes to 24 hours before real-time).**
Special Load Readings (SLR)	**A coincident set of simultaneous measurements for all distribution substations.**
System Flexibility Needs	**The flexibility needed by the electricity system to adjust to the variability of generation and consumption patterns, across relevant market timeframe.**
Target Year	**A year for which data and analysis are provided within the framework of the FNA methodology.**
Uncovered Flexibility Needs	**The additional flexibility needs identified by the FNA methodology, not expected to be met by new or existing resources based on ERAA or NRAA inputs.**
Upwards Flexibility	**Needs whose solution requires either increasing injection into the network or decreasing demand from the network.**
Voltage Issue	**A situation when voltage levels are not within the operational limits.**
Very Fast Flexibility	**The capacity able to react to aggregated D-1 or shorter horizons forecast error variations (5 to 15 minutes before real-time).**
Un-Utilised MIC	**The difference between a customer's contracted Maximum Import Capacity (MIC) and their actual peak demand (where**

	peak demand is lower than the MIC), representing reserved network capacity that is not actively used.

1. Introduction

1.1 The role of the Commission for Regulation of Utilities

The Commission for Regulation of Utilities (CRU) is Ireland's independent energy and water regulator. The CRU's mission is to protect the public interest in Water, Energy, and Energy Safety. The work of the CRU impacts every Irish home and business. The sectors the CRU regulates underpin Irish economic competitiveness, investment and growth, while also contributing to obligations to address climate change.

The CRU is committed to playing its role to help deliver a secure, low carbon future at the least possible cost, while ensuring energy is supplied safely, with empowered and protected customers paying reasonable prices and the delivery of a sustainable, reliable and efficient future for energy and water.

Further Information on the CRU's role and relevant legislation can be found on the CRU's website at www.cru.ie.

1.2 Background and Context

This report presents Ireland's first National Flexibility Needs Assessment (FNA), prepared in accordance with Article 19e of Regulation (EU) 2019/943, as amended by the Electricity Market Design Reform (Regulation (EU) 2024/1747)[5]. The Regulation requires each Member State to adopt a national report assessing the electricity system's anticipated flexibility needs over a forward-looking period of at least five to ten years. The objective of this requirement is to ensure that electricity systems are adequately prepared for increasing shares of renewable generation, rising electrification of demand, and more variable system conditions.

Under the Regulation, responsibility for adopting the National FNA report rests with the National Regulatory Authority (NRA) or another authority or entity designated by a Member State. In Ireland, the Commission for Regulation of Utilities (CRU) is the NRA responsible for adopting and publishing the Flexibility Needs Assessment report. The assessment has been completed in close collaboration with Ireland's electricity system operators, EirGrid and ESB Networks, and is underpinned by the data, modelling and analysis undertaken by the system operators within their respective roles.

The Utility Regulator (UR) is the designated entity responsible for preparing and submitting the FNA for Northern Ireland and, given the all-island nature of the electricity system and

[5] Regulation - EU - 2024/1747 - EN - EUR-Lex

market, the CRU has engaged with the UR throughout the process to support alignment, coordination and a shared understanding of flexibility needs across both jurisdictions.

To ensure consistency across Member States, the Regulation requires the use of a common methodology approved by the Agency for the Cooperation of Energy Regulators (ACER). In July 2025, ACER adopted Decision No. 05/2025 on the type and format of data and the methodology for TSOs' and DSOs' flexibility needs analysis. This Decision set out the scope of the assessment, the minimum content to be addressed, and the respective roles of national regulatory authorities and system operators, including the requirement for advance agreement on the scope of data and analysis.

In line with this framework, and as set out in the published Flexibility Needs Assessment Information Note (CRU/202627)[6], the CRU, EirGrid (Transmission System Operator) and ESB Networks (Distribution System Operator) agreed in advance the scope, assumptions and analytical approaches applied for this first FNA. EirGrid and ESB Networks have undertaken the detailed system-level and network-level analysis required by the ACER FNA Methodology, while the CRU has coordinated the overall process and adopted this National FNA report.

Reflecting the requirements of Regulation (EU) 2019/943 (as amended by Regulation (EU) 2024/1747) and the ACER methodology, this report presents:

- An assessment of Ireland's anticipated electricity system and network-level flexibility needs, including the timing, magnitude and location of those needs.
- An assessment of the different forms of flexibility that could contribute to meeting the identified needs, including non-fossil flexibility resources.
- An evaluation of regulatory, market and operational barriers to flexibility, alongside consideration of the role of digitalisation, to assess whether existing arrangements enable flexibility to come forward where it is most valuable.

The need for a structured, forward-looking assessment of flexibility reflects the evolving nature of Ireland's electricity system. The increasing penetration of variable renewable generation, together with growing electrification of heat, transport and industry, is changing how the system must be planned and operated. Flexibility — provided by resources such as demand-side response, energy storage and flexible generation — is expected to play an increasingly important role in maintaining security of supply, managing network constraints efficiently and enabling cost-effective decarbonisation.

1.3 Purpose of this Report

The purpose of this report is to set out the findings of Ireland's first National Flexibility Needs Assessment. The report identifies the anticipated electricity system flexibility needs over the

[6] Flexibility Needs Assessment | CRU.ie

medium term, including the scale, timing and location of flexibility requirements across the Irish system and transmission and distribution networks.

The National FNA provides a structured and transparent evidence base to support regulatory, policy and system planning decisions. In particular, the assessment is intended to inform consideration of future flexibility market arrangements, procurement mechanisms and enabling frameworks, and to support the setting of indicative national objectives for non-fossil flexibility in line with European requirements.

In completing this assessment, the CRU recognises that flexibility can be provided by a wide range of resources, including demand-side resources, energy storage, flexible generation and distributed energy resources capable of adjusting generation or consumption in response to system and network needs. These resources may be enabled through a range of policy, regulatory, market and operational arrangements, including market participation, flexibility products, connection arrangements and operational coordination.

Accordingly, the flexibility needs identified in this report should not be interpreted as prescribing a specific technology, commercial model, procurement route or policy outcome. They should also not be interpreted as indicating that it would be economic or efficient to meet all identified needs through additional flexibility. Some residual renewable dispatch down may remain where this reflects the efficient market or operational outcome. For implicit flexibility, market arrangements should recognise that participants will respond to price signals based on their own costs and preferences. Even where flexible capability exists, the efficient market outcome may still include some residual renewable surplus or unshifted demand. For explicit flexibility, procurement and product design should be informed by whether the expected benefits justify the associated costs.

As such, this report provides a forward-looking assessment of anticipated flexibility needs, based on agreed methodologies and assumptions, to support informed decision-making by the CRU, government, system operators and market participants. As the first iteration of the National FNA, this report establishes a baseline understanding of Ireland’s flexibility needs. Subsequent FNAs will build on this foundation as the electricity system evolves, data availability improves and market arrangements develop.

1.4 Structure of this Report

The structure of this Report is outlined below.

- Section 1 – provides background information and the legal basis underpinning the Flexibility Needs Assessment and associated methodology.
- Part A – explains the methodologies followed by the System Operators to complete the analysis to determine the future flexible needs at both the system and network level.
- Part B – sets out and explains the identified flexibility needs at both the system and network level.

- Part C – discusses the potential of different forms of flexibility to meet the identified flexibility needs.
- Part D – discusses the regulatory and market barriers to flexibility that have been identified as part of the assessment and considers the role of digitalisation.
- Part E – concludes and provides next steps following the publication of this Report.
- The appendices provide further data and analysis from the assessment.

In developing this report, the CRU has adopted a coordinated approach, drawing on detailed technical inputs from the System Operators (SOs). In particular, the material covered in Parts A, B and C has been provided by EirGrid and ESB Networks and reviewed and consolidated by the CRU for the purpose of this report. EirGrid and ESB Networks input and expertise also form a core part of the findings in Part D.

1.5 Related Documents

This report should be read alongside the following documents, which provide the regulatory, methodological and analytical context for Ireland's first National Flexibility Needs Assessment:

- **Regulation (EU) 2019/943**, as amended by the Electricity Market Design Reform (Regulation (EU) 2024/1747).
- **ACER Decision No. 05/2025** on the type and format of data and the methodology for flexibility needs assessments.
- **The CRU's Flexibility Needs Assessment Information Paper**[7] (CRU/202627), which provides an overview of the FNA process, objectives and timeline.

[7] Flexibility Needs Assessment Information Paper

Part A: Flexibility Needs Analysis Methodology

Target years

This assessment is required to cover at least two target years within a study horizon of 10 years. ENTSO-E and the DSO Entity were required to agree a single target year to be applied consistently across all countries, and their TSOs and DSOs. The target year must align with the Distribution Network Development Plan (DNDP) study year, the ERAA study year, and an EU climate policy milestone. 2030 was selected by ENTSO-E and the DSO Entity on this basis.

The second target year must align with a DNDP study year and an ERAA study year, and was to be agreed locally between the TSO, DSO and the relevant National Regulatory Authority (NRA). To determine the second target year the following information on the years covered by the most recent relevant studies was considered:

- ERAA – 2026, 2028, 2030, 2035 (https://www.entsoe.eu/eraa/2024/).
- DNDP, flexibility needs, 2026, 2028, 2030. (https://esbnetworksprdsastd01.blob.core.windows.net/media/docs/default-source/publications/distribution-network-development-plan-part-2-distribution-network-development-report.pdf?sfvrsn=9b372452_6).
- The core ECP-2.5 study horizons are 2028, 2030 and Future Grid. (https://cms.eirgrid.ie/sites/default/files/publications/ECP2.5-GSS-Industry-Engagement-Webinar.pdf).
- AIRAA (NRAA) – 2026-2035 (https://cms.eirgrid.ie/sites/default/files/publications/AIRAA-2026-2035_Inputs-and-Assumptions-Ireland.pdf)

Following discussions in the scoping stage of the FNA approach, EirGrid and ESB Networks decided the second target year should be 2028 and this was agreed with the CRU. The minimum of two target years was used for this first iteration of the assessment, and in future iterations work will be done to increase the number of target years in line with FNA methodology requirements.

2. System Level Analysis

2.1 Overall modelling approach

The methodology for the system level analysis for the FNA was developed in line with relevant European regulatory guidance, specifically the ACER Methodology, and tailored to the characteristics of the Irish power system. While the original scope set out a broad and comprehensive assessment framework, the implemented methodology reflects a proportionate and pragmatic application of this framework, taking account of data availability, model capability, and alignment with parallel system studies.

While the FNA methodology is a national requirement, a shared modelling and analysis approach was used for EirGrid and SONI with aligned assumptions. Data processing and submission requirements were then managed separately. The benefits to this approach include:

- The economic dispatch results which form the primary basis of the input data to be processed in the FNA methodology would be a more accurate reflection of market results as they would be based on wholesale market simulations with the whole all-island Single Electricity Market (SEM) rather than considering Ireland in isolation.
- While the reports need to be at national level, Article 1(3) outlines a requirement that "The quantification of system flexibility needs is carried out at bidding zone(s) level", showing an intent from the methodology itself of alignment at a bidding zone level – in the context of the Single Electricity Market, Ireland and Northern Ireland together form a single all-island bidding zone.
- The processes surrounding the development and operation of the AIRAA model are already carried out on an all-island basis. System constraints required to be modelled as per Article 8 of the ACER Methodology are SEM wide, such as the SNSP constraint.

Two options were considered for the main source of the basis for modelling:

- The All-Island Resource Adequacy Assessment (AIRAA) model, which is aligned with the requirements of the National Resource Adequacy Assessment (NRAA) as defined in the FNA methodology. This methodology uses a higher-level representation of the power system without the need for including detailed representation of the transmission network; and
- The Enduring Connections Policy (ECP) model, for iteration 2.5, which includes additional information and data, in particular operational constraints and the full transmission network model.

Following review, the AIRAA model was selected as the starting point for the system flexibility needs analysis as it is better aligned with the FNA Methodology, in particular Article 7(3) which requires that an NRAA model is used as the basis for the FNA model. Testing was carried out in the early stages of the modelling phase to consider how representative the results were of the flexibility needs of the Irish power system. A number of modifications were made to the

AIRAA model to incorporate elements which are key drivers of flexibility needs and flexibility capabilities. This included considering additional aspects in the model such as operational constraints, additional generator and interconnector technical characteristics, and reserves modelling within the context of the changes permitted to the model in-keeping with the FNA methodology Article 7 and Annex.

These changes necessitated rerunning the economic dispatch simulation (FNA model). Therefore, for system flexibility needs, the model chosen was the AIRAA 2026-2035 model, following an economic dispatch simulation approach as considered under Article 7(3)(b). Because of this, it was necessary to incorporate either, or both, short term and ramping flexibility needs into the model. Both of these flexibility needs were incorporated into the model. The details of the AIRAA model assumptions and inputs, which were the starting point for this analysis, are available in the following documents:

- https://cms.eirgrid.ie/sites/default/files/publications/AIRAA-2026-2035_Inputs-and-Assumptions-Ireland.pdf
- https://cms.eirgrid.ie/sites/default/files/publications/AIRAA-2026-2035_Ireland.pdf

2.1.1 Target for RES Integration

Article 8(7) of the ACER Methodology outlines requirements to extract and process or interpret values from the National Energy and Climate Plan[8] to help determine the level of RES integration targets. For this analysis these values have been taken from Table 9 at the link provided, where the RES-E target for 2028 is 60% and the RES-E target for 2030 is 80%.

2.2 RES Integration, ramping and short term flexibility needs

The assessment approach taken is that outlined in Article 7(3) (b) of the ACER Methodology, utilising an economic dispatch simulation based on NRAA assumptions but embedding ramping needs and short-term flexibility needs. These were incorporated into the model as follows:

- **Ramping needs:** including representation of generator properties which correspond to flexibility and impact on their ramping abilities. This included parameters such as, but not limited to, ramp rates up and down, cold/warm start times, shutdown times, minimum on/off times, and minimum stable generation levels, etc.
- **Short term needs:** Including "reserve objects" in the Plexos model with representations of the impact of day-ahead forecast errors, with inputs based on actual forecast errors from the residual load inputs (wind power, solar power, and load), with

[8] NECP

separate objects for upward and downward errors. Realistic values for the reserve objects were developed through use of historical data for the years 2024 and 2025 for differences between forecast and actual demand, wind, and solar. The short-term needs representing forced outages are included as Frequency Containment Reserves (FCR) and Frequency Restoration Reserves (FRR) which act respectively as primary and secondary reserves to cater for the largest potential loss. The short-term need for largest loss was covered by the existing FCR and FRR response which act as a primary and secondary upward reserve provision respectively. These already existed within the AIRAA model.

As a result of Article 7(4)(i), the task throughout the rest of this methodology is limited to assessing “the RES integration needs pursuant to Article 8”. This is because the impact of ramping flexibility needs and short term flexibility needs on the RES integration flexibility needs are implicitly included through the RES curtailment results from the model described above to the extent required under the scope of the ACER Methodology. This means that the analysis steps required to determine the impact on RES integration needs (i.e. all the steps up to paragraph 9(6) for ramping needs and paragraph 10(5) for short term needs) do not need to be carried out as their results are already implicitly met through the Article 8 analysis using the model as described.

In Article 7(4)(i), there is mention of analysis of economic dispatch results for ramping and short-term needs. This should be read in conjunction with the last paragraph in each of the relevant articles (Article 9(11) and Article 10(10)) which describes how this is to be done. These paragraphs mention that when the economic dispatch approach outlined above is used, then the task is limited to what is described in that paragraph itself (i.e. the analysis steps described in the rest of those articles do not need to be followed), which is based on extracting the uncovered ramping and short term needs either directly from the model or by comparing Energy Not Served (ENS) or RES curtailment indicators with or without the constraints relating to the need in question. As a result of the assumptions in EirGrid’s model there is no uncovered ramping or short term needs in the model (for example, given that it is based on the AIRAA model, it is satisfied from an adequacy perspective, and it appears that those resources in the model to help meet that capacity adequacy need can also sufficiently meet short term and ramping needs), and there is no ENS. Therefore, the analysis focused on the impact on RES curtailment.

Additional scenarios have been run (among a number of additional scenarios not relevant to this description) in the models where the short-term needs inputs of the model are removed, where the ramping needs inputs of the model are removed, and where the operational constraints are removed in order to provide results to meet Article 16(10) requirements to provide analysis of the interdependencies among the needs. By doing this analysis, it is possible to compare the RES curtailment results from the models of these scenarios with those in the base case RES curtailment Article 8 results, which provides a RES curtailment indicator of the short term and ramping flexibility needs which is in line with the requirements of Articles 9(11) and 10(10), alongside indicators for operational constraint needs, and transmission constraint needs too.

In summary, the results produced in line with the requirements of Article 8, the RES curtailment time series from the FNA model (representing what would be termed in Ireland surplus and curtailment, excluding constraint results which come from the ECP model) implicitly include the impact of short-term and ramping needs on RES curtailment within all of the results that use that timeseries, and therefore this meets the needs of Article 8 and part of Article 7(4)(i) (implicitly meeting the needs of Articles 9(6) and 10(5)). Results produced in line with the requirements of Article 16(10), will represent the impact on RES curtailment of all other drivers other than the individual short-term flexibility needs, and separately the same but for ramping flexibility needs. These can then be compared with the base Article 8 RES curtailment results, resulting in an individual RES curtailment time series for short-term flexibility needs and ramping needs, therefore meeting the needs of Article 9(11), 10(10), and the remaining part of Article 7(4)(i). Accordingly, all requirements for providing results for RES integration needs, short term flexibility needs, and ramping needs, relevant to the modelling approach required, have been met.

The following are some additional specific optional aspects outlined for consideration in the FNA methodology:

- The optional approach of considering an impact on flexibility from the schedule of exchanges due to market liquidity constraints that appear in extreme price situations was not adopted.
- The assessment does not include the optional approach differentiating between very fast, fast, and slow residual load variations.
- Due to SEM market design with mandatory balancing market participation, there was no need for additional analysis of the abilities for units to meet balancing energy product requirements.

2.3 Fine-tuning approach

In accordance with FNAM Article 14, the TSO needs to carry out an assessment of whether a “fine-tuning” process is needed to incorporate the impacts of various aspects in their analysis. For each relevant metric for this assessment in the FNAM, a threshold of 10% is used, where if the relevant impact of that aspect is less than this threshold then the fine-tuning process is not seen as “relevant” and does not need to be incorporated in the TSO analysis.

The Constraint results from the ECP model, show that the amount of RES dispatch down due to transmission network constraints is greater than this threshold (constraints in MWh being over 10% of the overall total annual level of RES dispatch down in MWh (see results in Sections 5.1.4 and 6.1)), so a fine-tuning process was carried out for incorporating the TSO network flexibility needs into the RES integration flexibility needs. More detail on how this was done is outlined in Section 3.1.

Below is a summary of how the fine-tuning relevance assessments were carried out for DSO aspects in the ACER Methodology:

- For the aspect of "downward distribution network needs" identified by the DSO, the results in Table 91, Section 7.4, showing the MWh values for downward distribution system flexibility needs, can be compared with the values in Table 22, section 5.1.4, which shows the RES dispatch down values in MWh that we have calculated, showing that the 10% threshold to be considered 'relevant' would not be met, and therefore fine-tuning was not carried out for this aspect
- For the "unavailability" aspect under the "prequalification process" and "temporary limits", current understanding is that this only relates to the processes that exist under rights given to DSO under SOGL Article 182. From TSO and DSO discussions, the only mechanism that could seem relevant in this regard at the moment is the Demand Side Unit (DSU) instruction set process whereby the DSO sets limits on certain sites from being able to take part in Demand Side Units at certain times;
    - Table 1 below outlines the values of the total Individual Demand Site (IDS) capacity and the IDS capacity which is subject to restrictions by the DSO making them unavailable through the dynamic instructions sets process;
    - Based on this, the impact is not greater than the 10% threshold required under Article 14, and therefore a fine-tuning process was not carried out for this aspect.

Table 1: IDS capacity total and with DSO restriction for 2025 and 2026

	2025	2026
IDS Capacity (MW)	679.02	516.92
IDS Capacity subject to restrictions through DSU Instruction Sets (MW)	8.15	9.82

2.4 Additional data and analysis

Additional modelling runs were carried out using a High RES scenario from the AIRAA model, with RES capacity sufficient to surpass Ireland's NECP targets when there is no curtailment, enabled through Article 16(11) and carried out with the analysis for Article 16(6), to investigate the impact this has on the base case results under Articles 8 and 16.

Table 2: Solar PV, onshore and offshore wind capacity for base and High RES scenario for Ireland and Northern Ireland

	Ireland			Northern Ireland		
FNA Scenario	Offshore Wind Capacity, MW	Onshore Wind Capacity, MW	Solar PV Capacity, MW	Offshore Wind Capacity, MW	Onshore Wind Capacity, MW	Solar PV Capacity, MW
2028 Base	25	6441	4768	0	1550	350

2030 Base	1354	7130	6279	0	1850	480
2028 High RES	407	7472	6195	0	1592.5	375
2030 High RES	3654	8456	8273	1000	1967.5	537.5

Table 3: Available VRES, % of Total Generation and Total Energy Requirement for different FNA scenarios

	Available VRES, % of Total Generation (potential penetration of VRES by energy, assuming no dispatch down).		**IE Base Available RES, % of Total Energy Requirement, RES generation / (Total Generation + Import – Export) (potential penetration of all RES by energy, assuming no dispatch down).**		
FNA Scenario	**IE Base**	**IE High RES**	**IE Base**	**IE High RES**	**NECP WAM Target**
2028 WS 34	53.35	62.90	50.66	63.24	60
2028 WS 28	51.47	60.96	49.92	62.38	60
2028 WS 4	51.81	61.52	50.70	63.38	60
2030 WS 34	64.12	88.09	65.35	96.36	80
2030 WS 28	62.64	87.02	64.53	95.39	80
2030 WS 4	63.30	86.85	65.69	96.82	80

Table 3 provides a summary of the penetration level of VRES that would be possible with full availability assuming no dispatch down from the level of VRES capacity and availability which is input to the FNA model (following the requirements of the ACER Methodology), across the Base and High RES scenarios. This is provided for both VRES on its own as a percentage of total generation, and for all RES as a percentage of Total Energy Requirement for comparison against the NECP target. The second of these metrics is included as it is the relevant metric to consider the extent to which the RES integration targets can be met, considering all RES (not just Variable RES) and comparing them with the Total Energy Requirement. The first metric which focusses on just the VRES element and considers it as a percentage of total generation rather than Total Energy Requirement is included to provide a clearer indication of the level of generation from the main drivers for flexibility needs considered in this analysis, which are Variable RES sources such as Wind and Solar.

Results from the Enduring Connection Policy (ECP) modelling should be considered alongside these results as additional contextual information, where they are considered as a representation of RES dispatch down from system and transmission network impacts. A summary of the overall results from this model is available at the following link:

- https://cms.eirgrid.ie/sites/default/files/publications/Constraints-Forecast-Studies-for-ECP-2.5-Ireland_summary.pdf,

The following webpage contains links to more detailed results from this and other previous versions of this model:

- https://www.eirgrid.ie/industry/customer-information/ecp-constraint-forecast-reports

2.5 Caveats relating to the methodology approach

The FNA is a new process, and the associated modelling required needed to follow specific guidelines. As such more than one existing model process was used to capture the information needed for the analysis.

The FNA methodology mentions potential relevance of the Economic Viability Assessment (EVA) process from the ERAA methodology – this process will be implemented in future iterations of AIRAA and therefore any modelling for this iteration of the FNA methodology did not consider the EVA context.

The analysis required under Article 8(5) with hourly, daily seasonal indicators for the residual load time series was carried out as required but compared with many of the other areas of the analysis there were limited insights gained from those indicators. Also, the FNA methodology required values to be provided in a certain way, however providing them in another way could be more useful and aligned with other related types of analysis. For instance, the methodology required average annual levels of dispatch down to be provided, rather than actual total level of dispatch down, which may be more useful. While there is some flexibility within the methodology to provide additional data, further modifications may allow Member States to gain additional insights to feed into local processes around setting targets for non-fossil flexibility.

There is also a lack of clarity on scenarios required. The FNA methodology requests that weather scenarios that are considered in the NRAA model are used, and as such there are 36 weather scenarios available. Three representative scenarios as identified in the AIRAA 2026-2035 process were used, knowing that running all 36 would be impractically slow, and running one representative scenario may be less than required. Running 3 as opposed to one trebled the time to run models and process and present outputs, increased model setup time and taking time from being able to run other potential beneficial scenarios such as additional flexibility scenarios, different VRES scenarios, sensitivity analyses around interconnector flows, etc. Further, requests for scenarios or investigations such as those prescribed in articles 16(6), 16(10), and 16(5) do not clarify if they must be done for all weather scenarios and target years or a single combination. In each case, further guidance on the number of scenarios expected would increase clarity.

For the RES integration flexibility needs, the methodology discusses using NECP targets as the input for determining the uncovered needs. The AIRAA RES inputs align with current national trends and projections informed by SEAI's 'Decarbonised electricity system study' data.

Selecting a set of inputs which represent a future in line with meeting NECP targets and eventually net-zero would have answered the question on the how much flexibility would be required to meet NECP targets rather than the flexibility requirement of meeting a generation adequacy scenario. This could either be a replacement to the existing methodology or modelled as a scenario.

The relevant terminology and definitions should also be considered carefully when interpreting the results, as there are differences in how similar terms are used locally and in the European arrangements. In particular, the EU FNA methodology appears to use the term "curtailment" to refer to dispatching down renewable generators for any reason, e.g. defining RES curtailment as "limiting the generation or transmission of renewable power for system operational reasons or grid-capacity reasons". In the SEM arrangements, there are more specific uses of terminology and meanings in definitions, such that at a high level "curtailment" refers to dispatch down for system-wide operational reasons, "constraint" refers to dispatch down for local network reasons, and "surplus" refers to dispatch down where available generation is in excess of what can be accommodated through demand and exports. The results provided in this report use a mixture of the EU FNA methodology terminology when considering dispatch down of all drivers together and the SEM terminology when specifying impacts of individual drivers.

In particular, in section 5.1.1 which contains the majority of the main results required by Article 8 of the ACER Methodology for RES integration needs, the ACER Methodology term "RES generation curtailment" is used to describe the metric being analysed in that section in order to align with the ACER methodology requirements. In this context "RES generation curtailment" is used in the ACER Methodology interchangeably with "RES curtailment" and is aligned to the definition in the ACER Methodology. As such it represents the combined RES dispatch down for all reasons and drivers, i.e. reduction of RES generation below the technically available level for system operational reasons and grid-capacity reasons when considered in ACER Methodology terms, or for surplus, curtailment, and constraint reasons when considered in SEM terms.

In the other sections, in particular from 5.1.3 to 5.1.6, 5.2, 5.3, 5.4, 6, and 8, the SEM terms "RES dispatch down", "surplus", "curtailment" and "constraint" aligned with the definition in the SEM arrangements are used to describe the reduction of RES generation below their technically available level in order to be aligned with how the results need to be further broken down into the individual, or grouped, drivers and reasons for that dispatch down. An example definition for "surplus", "curtailment", and "constraint" is provided below, and other SEM documents which provide example definitions for these terms include the following:

- The Renewable Energy Constraint and Curtailment Reports (Annual Renewable Energy Constraint and Curtailment Report 2025);
- The ECP Constraint Forecast Analysis Reports (e.g. Constraint Forecast Analysis Reports for Enduring Connection Policy (ECP) 2.5);
- The Shaping Our Electricity Future Roadmap v1.1 publication (e.g. https://cms.eirgrid.ie/sites/default/files/publications/Shaping-Our-Electricity-Future-Roadmap_Version-1.1_07.23.pdf); and
- EirGrid and SONI's definition of Curtailment and Constraint aligned with SEM Committee decision SEM-11-010 (e.g. https://cms.eirgrid.ie/sites/default/files/publications/Shaping-Our-Electricity-Future-Roadmap_Version-1.1_07.23.pdf)

In some instances, the results in this FNA report are categorised with full alignment to the SEM terminology ("surplus", "curtailment", and "constraint"), and in other instances the results are categorised as required by the ACER Methodology but utilising the SEM terminology in order to be consistent (i.e. "surplus+curtailment" for RES integration system needs as considered in ACER methodology, and "constraint" for RES integration transmission network flexibility needs as considered in ACER methodology).

The terminology used across the report varies where necessary to maintain consistency of meaning and avoid potential ambiguity. The ACER Methodology terminology is used where possible, in particular where it is the total RES dispatch down that is considered. SEM terminology is used to avoid ambiguity where the different drivers and reasons for dispatch down need to be outlined.

Below is a summary explanation of curtailment, constraint and surplus as defined in SEM terminology.

CURTAILMENT	CONSTRAINT	SURPLUS
System-wide operational issue Dispatch down applied to non-synchronous renewable generation for system-wide operational reasons. Where reducing the output of any or all such generators would alleviate the problem e.g. system security limits such as SNSP, inertia, voltage support or frequency stability.	**Local network issue** Dispatch down applied to non-synchronous renewable generation for local transmission network congestion reasons where only a subset of such generators in a specific part of the grid can contribute to alleviating the problem by reducing their output.	**System-wide generation / demand balance issue** Dispatch down applied to non-synchronous renewable generation where available generation exceeds what can be used through demand and exports.

2.5.1 Suitability of modelling approach

The needs and operational policies from Ireland's perspective are different to those being considered to feed into the methodology and ACER's follow-on work. In particular, the base scenarios following EU FNA Methodology requirements have results for annual RES dispatch down figures which are lower than would be seen from other modelling carried out by EirGrid focussed on RES dispatch down, the ECP model.

The EU FNA methodology requires either an ERAA or NRAA (in our case being the AIRAA) model must be used as a starting point for the FNA model, which has scenarios with input data, assumptions, parameters, and methodology focussing on the modelling of generation adequacy. The ECP model would have a different set of scenarios from input data, assumptions, parameters, and methodology focussing on the modelling of dispatch down of renewables. However, as outlined in Article 7(3)(b)(i), the economic dispatch simulation modelling in FNA must be "based on the scenarios used pursuant to paragraph (1) and the associated set of inputs, installed capacities, climate scenarios and outage patterns;", i.e. the scenarios and inputs from the AIRAA model.

While the results provided for the Base case scenarios give a good indication of a number of the features of the flexibility needs, the results from the latest ECP modelling process are considered by EirGrid to be more representative than the Base case FNA results of what would be expected for total annual dispatch down of renewables. The summary of the latest version of the ECP model is provided in the following document: Constraints-Forecast-Studies-for-ECP-2.5-Ireland_summary.pdf. Additional scenarios (namely the High RES scenarios) were developed for this FNA analysis to work within what is allowed in the methodology to provide additional results which offer useful insights into the value of flexibility in reducing RES

dispatch down when it is at the levels that would be seen from other similar analysis such as the ECP.
In the future it is recommended to further investigate the possibility of either changing the FNA Methodology or work within the FNA Methodology to ensure consistency with the ECP modelling approach that looks at total dispatch down in more granular detail.

2.5.2 Short Term and Ramping Flexibility Needs

For short term flexibility needs, the format of the forecast data required by the FNA methodology did not align with the forecast data availability in TSO systems. Therefore, the modelling approach utilised the best available data to achieve a practical delivery of an assessment of short-term flexibility needs.

For ramping flexibility needs, in the results outlined in Section 5.2, no uncovered needs resulted from the model, and the relative impact on the RES Curtailment as analysed under the ACER Methodology Article 10(10) is very small. However, this must be strongly caveated that this is in relation to "ramping" as it is defined in the Flexibility Needs Assessment context, which does not reflect the way that EirGrid and SONI's Ramping Margin is considered from transmission system operational and planning perspectives, how it is defined and calculated through evaluating both ramping capability and ramping margin requirements. Therefore, any outcome of analysis for ramping under the FNA should not be interpreted as having any meaning towards the current considerations for Ramping Margin in the SEM.

In the ACER Methodology, the following definitions and calculations are used to consider ramping flexibility needs:

- ***Article 2(2)(y):*** *'ramping needs' refer to needs associated with variations of the residual load assuming perfect forecast conditions;*

- ***Article 9(1):*** *For each MTU and weather scenario for each target year, the TSOs shall extract the residual load from economic dispatch results pursuant to Article 7(3). The TSOs shall calculate the variations of this residual load, i.e., the changes in the level of the residual load between consecutive MTUs.*

- ***Article 9(2):*** *2. For each MTU and weather scenario for each target year, pursuant to Article 6(1), the TSOs shall extract from the economic dispatch results pursuant to Article 7(3) the dispatch of flexible resources (generation, storage and demand units), as well as the schedules of exchanges. The dispatches and schedules are used to calculate the ramping residual margins on the generation, storage, demand assets and exchange capacities by means of all the following:*

  a) the difference between the dispatched power production and the minimum and maximum power of the generation assets (on unit or aggregated level), including renewables;

  b) the difference between the dispatched off-take and the minimum and maximum power of the demand and storage assets (on unit or aggregated level);

c) the difference between the scheduled import and export and the available exchange capacity

Ramping Margin in the SEM is defined as the guaranteed margin that a unit provides to the system operator at a point in time for a specific horizon and duration as follows:

- Ramping Margin 1 is the increased MW output or reduction in demand, a unit can provide, within one hour of receiving a dispatch instruction and maintaining that MW output for a further two hours after the one-hour period has elapsed.
- Ramping Margin 3 is the increased MW output or reduction in demand, a unit can provide, within three hours of receiving a dispatch instruction and maintaining that MW output for a further five hours after the three-hour period has elapsed.
- Ramping Margin 8 is the increased MW output or reduction in demand, a unit can provide, within eight hours of receiving a dispatch instruction and maintaining that MW output for a further eight hours after the eight-hour period has elapsed.

The detailed calculation of the SEM Ramping Margin requirements is outlined in the following document:

- https://www.sem-o.com/sites/semo/files/documents/general-publications/Ramping_Margin_Requirements_in_Scheduling.pdf.

This shows that the requirements include consideration of parameters such as renewable forecast uncertainty, demand uncertainty, and interconnector and tie-line uncertainty.

The ramping margin tool (RMT) used in control centre operations is based on the results of the economic dispatch from the TSO's Long Term Schedule (LTS) to calculate the system ramping capability up/down and the corresponding renewable generation forecasts to identify the system ramping needs over different operational timeframes. This is further used to identify scenarios where the system cannot provide enough ramping capability to meet its ramping needs with a sufficient margin. Similar principles are applied in the evaluation of both ramping capability and needs in the planning timeframes. The RMT relies on the unit's comprehensive Technical Offer Data to calculate the system ramping capability for each generating unit such as ramp up rates over different ramp up/down stages, start-up/shut-down characteristics, minimum up/down times and many other ramping capability information/limitations. It does not consider a contribution from any energy limited storage units, imports and exports on interconnectors towards meeting ramping needs, and considers outages e.g. it does not consider contribution from unavailable generators.

In summary, the ramping flexibility needs in the FNA methodology are distinct from, and not to be confused with, Ramping Margin considerations in the SEM context. The FNA ramping needs identify the flexibility required to manage residual load variation under the scenarios and assumptions assessed. By contrast, the Ramping Margin approach in SEM is an operational tool to manage TSO needs on the day and forms an important part of system operation and planning. These Ramping Margin arrangements have been developed as a best-in-practice approach for the SEM to ensure sufficient ramping flexibility and capability to manage the TSOs' ramping needs on an operational time horizon considering the characteristics of the SEM. The FNA ramping needs should therefore be interpreted as a methodology-based assessment of flexibility requirements associated with changes in residual load under the scenarios considered, rather than as an assessment of the adequacy or effectiveness of existing SEM Ramping Margin arrangements.

3. Transmission Level Analysis

3.1 Methodology

The approach to Transmission Network Flexibility Needs analysis modelling is based on a combination of the following Flexibility Needs Assessment articles:

- *Article 12(1) –downward network flexibility needs resulting in RES generation curtailment due to transmission network constraints.*
- *Article 12(2) – results fed into fine-tuning of the RES integration needs.*
- *Article 12(3) –a network simulation model was used, specifically the ECP model, and ran it in a way where there were separate runs with and without the network modelled such that the specific constraint aspects of RES dispatch down results could be separated out.*
- *Article 12(6) – the network data to the ECP model are based on the most recent available Network Delivery Portfolio (NDP, Q3 2025), and selecting the results to take was based on which ECP scenario most closely matched the relevant FNA scenario.*

Upward flexibility needs were not analysed as allowed under the optional approach in Article 12(4).

The transmission network is not included within the AIRAA model, and therefore not included in the FNA model. The effects of transmission constraints / transmission network flexibility on RES integration needs have been derived from analysis performed on the ECP model, which has full nodal representation of the transmission system across Ireland. These results were applied to RES curtailment outputs through a fine tuning process to ensure that transmission network constraints are represented. This was done in the following way:

- The ECP model was run for the relevant target year, for scenarios that had similar generation capacities (with higher VRES capacities in the High RES scenario modelled) and operational constraints to what was considered in the FNA model, with and without transmission constraints.
- A time series of the specific constraint volumes were attained from this, so that they could be added directly in each relevant hour to the RES curtailment time series from the FNA model.
- Additional sense-checking of the results was carried out to ensure rational results (e.g. no hours where dispatch down is greater than available etc.)

The assumptions document for the relevant ECP model is at the following link:

- https://cms.eirgrid.ie/sites/default/files/publications/ECP-2.5-Assumptions-Document-Final-Update.pdf

A summary of the overall results from this model is available at the following link:

- https://cms.eirgrid.ie/sites/default/files/publications/Constraints-Forecast-Studies-for-ECP-2.5-Ireland_summary.pdf,

The following webpage contains links to more detailed results from this and other previous versions of this model:

- https://www.eirgrid.ie/industry/customer-information/ecp-constraint-forecast-reports

4. Distribution Level Analysis

The core principle adopted in assessing DSO network needs – in line with Article 11 (DSO network flexibility needs) of the ACER methodology – was to identify the locations where distribution stations were likely to exceed their capacity. In adopting this approach there are 2 points to note:

- Article 3 – Roles and responsibilities clause 2a. indicates that the DSO will identify flexibility which 'the DSO is forecasting to use in order to prevent or solve congestion or voltage issues. While station congestion has been analysed to identify the flexibility needs, a more qualitative approach has been taken for voltage (this is set out in Section 4.4).
- Article 3 – Roles and responsibilities clause 2a. also sets out that Downward Flexibility Needs should be identified. A high level assessment of Downward Flexibility was undertaken with two specific use cases which are set out below.

This approach of focussing on distribution station congestion is appropriate for a number of reasons. As has previously been flagged by ESB Networks, a shortfall/expected shortfall in station capacity has been identified[9] as an issue which is to be addressed. However, in addition and based on experience to date in procuring flexibility services, as the geographic area which can contribute to addressing congestion at the stations is significant (compared, for example, with an approach which was focussed on MV feeder congestion), this will provide a larger group of customers with an opportunity to participate in any procurement process following on from this publication.

While this approach does not identify flexibility services required to address voltage issues or network overloads, as will be seen later in this document (Section 4.4), procuring Upward Flexibility Services at station level will increase the voltage (where voltage is low). As a result,

[9] ELECTRICITY DISTRIBUTION NETWORK CAPACITY PATHWAYS – CONSULTATION REPORT – Delivering the Electricity Network for Ireland's Clean Electric Future

where voltage may be low or even outside standard then Upward Flexibility Services will improve the voltage in an area.

In terms of the approach to downward flexibility, there are two scenarios developed which could contribute to a need to constrain generation for reasons of distribution congestion:

1. The first scenario relates to the potential need to reduce the output from generators connected on a flexible basis. There are currently four generators contracted on a flexible basis and these were each analysed using assumptions as to expected output and load. In this case, only an estimate for 2025 has been calculated.

2. The second scenario relates to the potential need to reduce the output from micro-/mini-generation due to the overloading of local substations. As with the first scenario, assumptions were used with regard to load and solar production to identify any issues. While estimates were calculated for both target years, the growth trajectory is subject to change.

In future iterations of the FNA, ESB Networks will consider whether the approaches outlined above still apply or whether a modified approach should be adopted.

While the initial review of station capacity versus load identified all locations where there was potentially a shortfall in capacity, flexibility needs were only identified at locations where there is not an identified capital project which is estimated to be delivered before the target year. Where capital projects have been identified, such projects are expected to address the shortfall.

4.1 Methodology

This section will focus on:

- Data Sources – in line with Article 3 (Section 4.1.1)
- Defining station capacity for the purpose of this analysis (Section 4.1.2)
- How load estimates were developed for 2028 and 2030 (Section 4.1.3)
- Various milestones to refine stations for assessment (Section 4.1.4)
- Use of load profiles (Section 4.1.5)
- Analysis work undertaken (Section 4.1.6)
- The 110kV hub assessment – identifying the potential dual benefit of flexibility services (Section 4.1.7)
- Checkpoint against the Demand Capacity Headroom Report (Section 4.1.8)

4.1.1 Required Data (Inputs)

In line with Article 3 of the ACER methodology, this section specifies the necessary data needed to identify the flexibility needs. Table 4 below summarises the list of the required inputs.

Table 4: List of required inputs

Input	Description
Demand Capacity Headroom Report 2025	This workbook provides indicative "headroom" capacity (in MW) available for new demand at existing 110kV and 38kV substations. The capacity is based on peak load. demand-capacity-headroom-report-2025.xlsx
Distribution Network Development Plan (DNDP)	The Distribution Network Development Plan (DNDP) outlines the infrastructure CAPEX reinforcement plans and also indicates areas of the network where flexibility services may be required. DNDP | ESB Networks
Special Load Reading (SLR) main report 2024-2025	The SLR report reflects the co-incident load reading at all stations on system peak day (as identified by EirGrid). The SLR also records summer valley load, but the valley load is not used within the FNA analysis.
Station Load Profile (SCADA)	Half hourly load profiles extracted from SCADA systems.
Load Growth Rate	Estimates of load growth rates on an area-by-area basis align with those used by the Network Development team (within ESB Networks) (who identify the need for capital works) and the Demand Capacity Headroom Report 2025 (part of the DNDP).
New Loads Data	These are sourced from internal records of demand applications received.
Limited Capacity Stations' List	This is a list of distribution stations which are coming close to capacity.
Programme of Capital Projects	This list will include all capital projects underway or in planning which are estimated to be delivered not later than winter 2030.

4.1.2 Establishing station capacity

The first stage of the analysis was to establish the station capacity against which expected load in each of the target years would be compared.

There are multiple capacity measures which can be used:

1) **Installed capacity** Each station on the distribution system has installed capacity which is established by virtue of the nameplate rating on the transformer. For example, the installed capacity of a typical 110kV/38kV station could be 2*63MVA = 126MVA. However, the station installed capacity is not used for the purposes of planning capital reinforcement, or - in this case -identifying the need for flexibility services. This is to take account of the possibility of a plant outage – due to fault or planned works.

In ESB Networks there are two different planning capacity figures which could be used for this Flexibility Needs Analysis, and these are aligned with European standards. These are:

2) **Firm Capacity** – typically 140%/150%[10] of the rating of a single transformer at a two-transformer station. This rating reflects the long-term overload capability assuming cyclic load[11] at the station.

3) **Non-Firm Capacity** – typically 180% of the rating of a single transformer at a two-transformer station. This rating reflects the short-term overload capability assuming cyclic load[5] at the station and assumes that the load can be reduced to the firm capacity of the station within 30 minutes.

As an example, the 2*63MVA station referenced above would have

- Firm capacity of 63MVA*1.4 = 88.2MVA
- Non-firm capacity of 63MVA*1.8 = 113.4MVA

Once the station capacity has been established, this can be compared against the forecast load.

For the purpose of the FNA, ESB Networks have compared the station loading against non-firm capacity. This decision was taken as most stations have sufficient transferrable load to allow station loading to be reduced to the firm capacity within a short period of time. These load transfers can typically be managed with minimal cost to the End User.

4.1.3 Use of special load readings

Once station capacity has been established, the next step is to identify the load and forecast load to be compared against the capacity. There were two different sources for base load data that were used during the analysis:

1) The Special Load Reading (SLR) Report – Specifically Peak Load

   This report is based on loads measured on the day of the overall system peak (as identified by EirGrid each year). The SLRs as a result reflect the co-incident load at all stations on that day and therefore represent a good record of peak loads on the system. The SLRs are also intended to reflect actual demand rather than net demand. For this reason, any large, embedded generation at a station is added back to the load. This will be an important factor when the use of SCADA load profiles is described later in the report.

   The SLR report allowed ESB Networks to focus on a single read for the almost 600 distribution stations on the system and therefore was used as a first filter in identifying congested stations. The most recent SLR report was used for the analysis and reflected peak load for the winter period 2024/25.

[10] 150% overload allowed for 110kV/MV or 38kV/MV in winter; 140% overload allowed for 110kV/38kV in winter.
[11] Cyclic load is a load with peaks and troughs. As such the periods of lower load will allow for transformer cooling.

2) SCADA load profiles

SCADA records the load at 110kV and 38kV stations every 30 minutes throughout the year. As the time element of flexibility is very important, SCADA annual load profiles allowed for a more detailed analysis and the identification of needs on a MWh basis.

Growing the SLRs to predict future load growth

As noted earlier, 2028 and 2030 were selected as the target years for which flexibility needs are to be identified. With this in mind, the first step of the analysis was to establish the expected load at each station, and in each of these target years with the 2024/25 SLR as the base load. In line with normal practice in ESB Networks, when forecasting future expected load, there are two main factors to consider:

- Expected growth in the existing load base. This can be due to small new connections or small increases in load used by existing customers.
- The addition of new large loads or large increases in Maximum Import Capacity (MIC) of existing customers.

The following sets out how the FNA methodology catered for both of these factors:

- Application of growth rates - In line with the current approach of the Network Development team, varying growth rates were applied countrywide. The growth rates per year varied from 2.4% per annum to 4.6%. For the 2028 target four years growth was applied to the SLR station load (2024/25). For 2030, a total of six years growth was applied. Growth rates were applied to the SLR load, but not to any new large loads.
- New loads - In addition to the underlying growth in load, the impact of newly contracted capacity was considered. Any new load (or increase in load) application which entered into a connection agreement with ESB Networks by the nominated freeze date of 19th September 2025 was added to the SLR stations load.
    - The new load was assumed to be energised by winter 2026
    - In line with the approach of the Network Development team a diversity factor was applied (76.5%)
    - No additional load growth was applied to these new loads. i.e. the load impact in each year was a fixed amount

Using the load growth and the new load, a load figure for each of the target years – for comparison against the station capacity – was available.

4.1.4 Milestones

Milestone 1 – SLR + growth + new loads versus Capacity

All distribution stations were assessed and shortlisted for further assessment where the forecast load (using SLRs as the base) exceeded the non-firm capacity of the station.

Milestone 2 – Validated list

The station list generated under Milestone 1 was further validated by comparing it with stations identified as being congested based on work done by the Network Development team (within ESB Networks). The two pieces of work which were used were:

1. The Limited Capacity List – which is a list of stations where the actual load (SLR 24/25) was greater than the firm capacity.

2. The Demand Capacity Headroom Report[12] - which is part of the Distribution Network Development Plan.

These lists were used to verify the results of the approach taken. Comparison against these lists occasionally identified additional information – for example load transfers which were planned that had not been identified in earlier analysis – which could lead to a location being added to or removed from the Milestone 1 list. On other occasions, apparent inconsistencies were due to differences in assumptions which were acknowledged and did not impact on the list for the FNA.

Any inconsistencies between this work and the Milestone 1 station list were investigated and the Milestone 1 station list modified if appropriate.

Milestone 3 – Capital Programme

Having established the station list from Milestone 2, this list was compared against the programme of capital works to be delivered in PR6. Where there were capital works which added transformer capacity in the location in question it was investigated further. Examples of such projects include:

- Uprating the congested station with larger transformers (e.g. 1*31.5MVA to 2*63MVA).
- Adding additional transformer(s) – e.g. 1*5MVA to 2*5MVA – to the congested station.
- Building a new station in a neighbouring area and transferring load from the congested station.
- Adding new capacity to a neighbouring station and transferring load from the congested station.

Where the capital project was confirmed as a project which would address the shortfall in capacity versus expected load and that project is expected to be delivered prior to 2030, the flexibility needs associated were amended as follows:

- Where the delivery date of such capital projects was before end 2028 (the first target year), flexibility needs at that location are not listed.
- Where the delivery date of such capital projects was between 2028 and 2030, flexibility needs are listed for 2028[13] but not 2030.

[12] Demand Capacity Headroom Report 2024 considered as the latest version wasn't available at that time. A further check on the 2025 update was considered later in the process.
[13] The exception being where the load forecast for 2028 did not exceed the non-firm capacity at the station.

As a result of this work, more stations/locations were removed from the list of locations where there were flexibility needs which then generated the Milestone 3 list.

4.1.5 SCADA Load Profiles

Once Milestone 3 list was available, a full year's load profile was generated for each station on the list. The time period used in general was 1 July 2024 to 30 June 2025. These profiles were used as a basis to generate profiles for 2028 and 2030 by applying growth rates and adding new loads[14] in a similar fashion to that set out for SLR.

Once the profiles were available, data cleansing was undertaken. There were two main elements to this:

- 'Spikes' in the data were removed. These could be associated with short-term faults or load transfers.
- Missing data or zero data was identified. One of two steps was then taken:
    - The missing data was populated with data from neighbouring timeslots.
    - Where there was a significant volume of missing or zero-value data – a total of five 38kV/MV stations - the overall timeframe was changed to the calendar year of 2025 (1 January- 31 December 2025).

Once the cleansed profiles for 2028 and 2030 were available, there was a further checkpoint as follows:

- In some cases, the peak load based only on the SCADA profile (cleansed) was less than the load at system peak, and less than the non-firm capacity at the station. This could be due, for example, to embedded generation reducing the load at the station[15]. Where this was the case, the station was also removed from the list of locations for flexibility needs[16].

4.1.6 Identifying Flexibility Needs

The list of stations for further assessment was identified based on the steps above (section 4.1.4 and 4.1.5), and then the annual load profiles of each station were compared against the station non-firm capacity to identify:

- The peak MW need at the station across the full target year[17].
- The total MWh need at the station across the full target year.
- The time blocks across the year when the flexibility needs were present[18].

[14] Where new loads were being added to the station profile, it was assumed that the new load had a similar profile to the station profile.
[15] Earlier in the report it was noted that SLRs added any embedded generation to the net demand to ensure that the SLR reflected actual demand.
[16] Only a small number of stations were removed based on this step.
[17] The peak MW need = peak load-non-firm capacity
[18] In some cases – where there were widespread needs – an approach to describing the time block was used to summarise the need.

- The duration of the longest need across the year[19].

4.1.7 110kV Hub Assessment

It is important to acknowledge that the nature of flexibility services is that flexibility procured at lower voltage levels can – in some instances – address problems arising at higher voltage levels. This is a significant advantage of flexibility services compared with capital works and will arise when peak loads are aligned.

There were several locations across the country where a need for flexibility services was identified at a 110kV/38kV station (the Upstream Station) and also at one or more 38kV stations (Downstream Stations) fed from same. Where this was the case, the basic methodology was to compare the needs at the upstream station at each 30 min slot, with the total needs at the downstream stations for the same time slot. Where the needs at the 110kV station could be addressed in full or in part by flexibility which may be procured for the 38kV station congestion, the 110kV station needs were reduced accordingly.[20]

4.1.8 Comparing Identified Flexibility MW with Demand Capacity Headroom Report 2025

Once the flexibility needs were identified in terms of peak MW and total MWh, these values were compared against those reported in Demand Capacity Headroom Report 2025 – which had been published end 2025.

As per the comparison with the Demand Capacity Headroom Report 2024, and the Limited Capacity List (Milestone 2), any inconsistencies were investigated and the FNA results modified where deemed appropriate.

4.2 Assumptions Used for the Flexibility Needs Analysis

The following key principles and assumptions have been adopted for the calculation of Upward Flexibility Needs at a national level.

[19] Primarily to identify places where the longest duration was greater than 5 hours, and as such flexibility services were unlikely to address the full need.
[20] The zonal summaries will however set out the needs before and after the hub assessment.

Table 5: Assumptions for upward flexibility

Category	Description
Assessment Scenario (station/transformer capacity)	Flexibility needs identified for transformer overloads only. As a result, neither voltage issues, nor network capacity issues, are addressed directly. Export only[21] transformers have not been assessed. Transformers on 'cold standby[22]' have not been assessed.
Load Growth Rates	Approved load growth rates (Base View) have been used in line with those published in the Demand Capacity Headroom Report 2025 (part of the DNDP). Load growth rates are included in Appendix E.
Consideration for New Loads	Newly contracted load (i.e. both new connections and customers increasing their Maximum Import Capacity, which have an executed connection agreement with ESB Networks) have been considered. Where an existing customer has applied for and accepted an agreement to reduce their MIC, the proposed reduction has been excluded from FNA assessment (i.e. the forecast load is not reduced by this amount)[23]. The freeze date for consideration of newly contracted load is ***19th September 2025.*** Load growth is not applied to the load of new customers. All new loads have been diversified using a factor of 76.5% and this diversified load added to the base load in each year.

[21] Export only transformers refer to those transformers on which there is no demand customers and only generation customers are connected.
[22] Transformers on 'cold standby' are those not in normal service but used only under plant outage scenarios
[23] In the majority of cases such a request for a reduction in MIC does not reflect a change to the customers use of energy, but rather reflects a formalisation of unutilised MIC.

	New loads are assumed to be energised by 2026.
Existing Loads	Unutilised MIC has not been considered for the FNA.
Methodology for Data Cleansing	With a view to avoiding skewing the results of the FNA, the data within load profiles used in the FNA has been cleansed to remove intermittent spikes or impact on the profile of non-normal feeding arrangements.
PR6 Capital Programme of Work including Accelerated Delivery programme	Assessment assumes that the capital programme will be delivered in full and on schedule.

4.3 Differences between DNDP and FNA

As a general principle and as directed in the ACER methodology – most specifically Articles 3 and 6 – the principles and methodology adopted for the FNA are aligned with that used in the DNDP. The main differences are outlined in table 6 below:

Table 6: Variations between DNDP and FNA

Category	DNDP	FNA
Locations Assessed	Only locations where capital works were planned for delivery in PR5 or PR6, but a need arose prior to estimated delivery date.	All locations where the station load was greater than non-firm capacity unless a capital project addressed the need prior to 2028 or 2030
New Loads with Executed Connection Agreements	Only considered for Dublin and not for other planning zones.	To be considered for all the planning zones.
Base Loads from SLR	SLR 23/24 used.	SLR 24/25 to be used.

Target Years	2026, 2028, 2030	2028 & 2030
SCADA Profile	01/01/24 - 31/12/24	01/07/24 - 30/06/25
Station Capacity for Standalone Transformers	100% of the individual transformer capacity.	90% of the individual transformer capacity.

4.4 Voltage Assessment

Article 3 clause 2 sets out that DSOs should identify flexibility to '*prevent or solve congestion or voltage issues'.* While the flexibility services required to address any voltage issues were not explicitly identified, power flow studies were undertaken to identify the positive impact of Upward Flexibility Services on areas of low voltage.

These assessments were carried out on a small sample of stations where flexibility needs were identified. A number of points were considered to ensure that the stations selected gave a good representation of the positive impact of flexibility on voltage across the country.

The stations selected were all 38kV/MV – as the majority of stations where flexibility needs were identified are 38kV/MV. The stations were to include both urban and rural areas. Typically, voltage problems are more prevalent in rural areas where feeder lengths will be longer. However, it was important to prove the concept for both.

The five major urban centres - Dublin, Limerick, Galway, Cork and Waterford were excluded as being outliers. Stations with an irregular profile were excluded as these were also considered to be outliers.

The stations selected were:

- Carrickmacross 38kV/MV from area Cavan (Zone 8) - Urban.
- Fermoy North-38kV/MV from area Fermoy (Zone 25) - Rural.
- Little Mills 38kV/MV from area Dundalk (Zone 7) - Rural.

4.4.1 Methodology

The load profile of the stations listed was modelled within a power flow model[24] for a selected time period instead of the whole year[25]. The time period modelled was based on longest duration of flexibility need for each station. The analysis period was then defined as extending from one day prior to, and one day beyond, the calculated longest duration of flexibility (detail set out in table 7 below.)

[24] PSS Sincal was the software used.
[25] This was to improve the clarity of the results.

For example, the longest required duration of Fermoy North for 2028 is 19.5 hrs extending from 27th Feb 2028 (0500 hrs) until 28th Feb 2028 00:30 hrs. Therefore, the SINCAL cycle period for the analysis is taken from 26th Feb 2028 until 29th Feb 2028 (considering 2028 as a leap year).

Table 7: Determination of Study Cycle Period

Station	Target Year	Longest Required Duration	SINCAL Cycle Period
Fermoy North-38/MV	2028	19.5 hour [27/02/2028 05:00:00] - [28/02/2028 00:30:00]	26/02/2028-29/02/2028
	2030	No flexibility need.	No flexibility need.
Carrickmacross-38/MV	2028	2.5 hour [18/11/2027 16:00:00] - [18/11/2027 18:30:00]	17/11/2027-19/11/2027
	2030	5 hour [13/02/2030 08:30:00] - [13/02/2030 13:30:00]	12/02/2030-14/02/2030
Little Mills-38/MV	2028	18 hour [09/01/2028 06:30:00] - [10/01/2028 00:30:00]	08/01/2028-11/01/2028
	2030	20 hour [04/01/2030 07:00:00] - [05/01/2030 03:00:00]	03/01/2030-06/01/2030

Time Series Power Flow on PSS Sincal was initiated for two scenarios:

a) *Base Scenario:* This has the actual load profile (grown to the relevant year) without any flexibility services.

b) *Flexibility Scenario*: This assumes all flexibility services are procured and activated. On this basis, the flexibility needs were subtracted from the actual loading profile (grown to the relevant year).

The following are the results obtained for Fermoy North 38kV/MV for 2028[26].

Figure 1: Load Profile - Fermoy North 38kV/MV - 2028

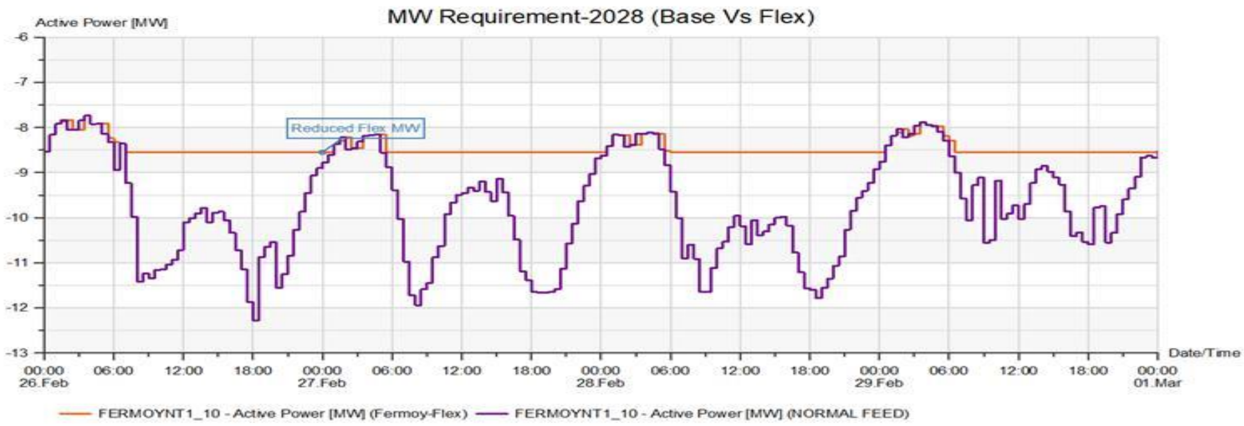

Figure 1 shows the load at the station without any flexibility services activated (purple) and with the flexibility services activated (orange)[27].

Figure 2: Voltage Profile - Fermoy North 38kV/MV - 2028

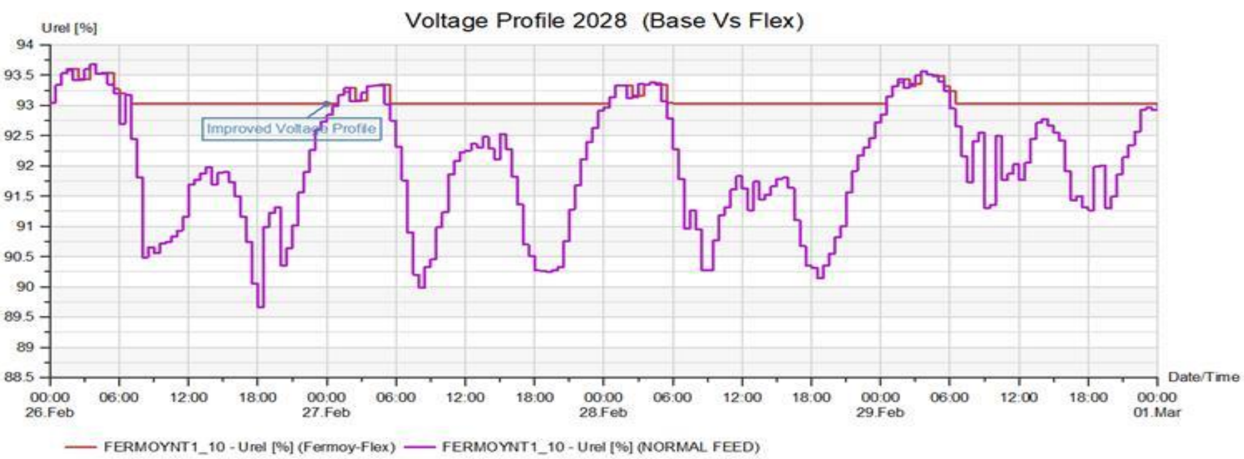

Figure 2 shows the voltage profile corresponding to the load profile[28]. Once again, the voltage without flexibility services activated is in purple. (It should also be noted that – for the purposes of the study – tap changers and boosters were switched to 'OFF'. This was to ensure that the explicit impact of Upward Flexibility Services on the improvement of voltage profile was evident.) The voltage profile where flexibility services were activated by the DSO is shown in orange.

[26] Remaining results are included in Appendix F.
[27] As active power is shown as injection of MW in PSS Sincal, load fed from the station is shown as negative.
[28] The x axis shows voltage as a % of nominal voltage.

Figure 2 shows that in the base loading scenario (purple line) the lowest voltage is approximately 90% of the nominal (equivalent to approximately 9.6kV). However based on the assumption that required flexibility services are procured and activated, a voltage improvement of 3% is observed (lowest voltage is approximately 93% of the nominal - equivalent to approximately 9.9kV).

This result shows that procuring and activating Upward Flexibility Services has a positive impact on low voltage.

4.5 Downward Flexibility

Article 3 clause 2 sets out that DSOs should identify both Upward and Downward Flexibility Needs. Downward Flexibility Need is defined (within the ACER document) as a need whose solution requires either decreasing injection into the network or increasing demand from the network.

On the basis of the ACER definition, a Downward Flexibility Need is likely to arise when there is too much generation on the system and not enough demand. Typically generation connections to the distribution system are on a firm basis such that the generator's full Maximum Export Capacity (MEC) can be accommodated under normal feeding arrangements, or under N-1 (where at least one item of plant is out of service). Where a connection is made on such a basis, it would be very rare for the generation to cause network congestion and as a result drive a need for Downward Flexibility.

There are, however, a limited number of flexible[29] generation connections on the distribution system, and in addition there is a growing number of micro- and mini-generation connections. Using these two scenarios, ESB Networks has undertaken two assessments of the potential need for injection to be decreased for reasons of distribution congestion:

a) The first assessment identified the likely MWh of reduction of the currently contracted flexible generation (there are currently four connection agreements accepted under Pilot 4 which is described in more detail in Section 4.5.1 below. One of the four was energised in Winter 2024)[30].

b) The second part of the assessment analysed the impact of micro- and mini- generation across the country and the possible need to limit the export of such generation to avoid overloading local MV/LV substations.

In both cases a) and b) above the analysis was undertaken based on transformer capacity.

Under assessment a) – the transformer capacity which was relevant was the HV/MV capacity which drove the need for a flexible connection offer to be issued (rather than a firm offer).

[29] Flexible for reasons of distribution congestion

[30] Flexible Access to the Distribution System for Renewable Generation

Under assessment b) - the transformer capacity which was relevant was the MV/LV substation capacity.

4.5.1 Pilot 4 Overview

Pilot 4 was first identified in 2022 as a pilot to be established under the National Network, Local Connections (NNLC) programme. The purpose of the pilot was to expand the availability of flexible generation connections to the Distribution System.

A generator may benefit from a flexible connection if there are several existing generation connections to the station in question such that under minimum load condition there is potential for the reverse load[31] on the transformer to exceed capacity. In such a scenario, for a new generation connection to be offered a firm connection, they may be required to pay for significant network infrastructure and cannot be connected until that infrastructure is built.

In Pilot 4 generators were offered flexible connections[32] where the following conditions applied:

- Their full Maximum Export Capacity (MEC) (firm + flexible) could be accommodated if the station in question was in normal feeding configuration with two transformers in service, except;
- For loss of a transformer, the remaining transformer would be overloaded if:
  - Station load was at minimum and
  - Other, firm generation was generating at their full MEC.

By accepting a flexible connection - which would reduce their export where a transformer was out of service - the new connection can avail of a cheaper and faster connection.

<u>Estimate of Likely Downward Flexibility – Methodology for 2025</u>

The work was based on 4 key principles:

- Due to how the connection of generation to the distribution system is studied by ESB Networks - at minimum load during a transformer outage – only the firm MEC can be consistently availed of by the Pilot 4 flexible generator. So that if the level of load at the station is at minimum or lower[33], and there is a transformer outage, the flexible generation may need to be constrained.
- If both transformers in the station are available, there should be no need to constrain the flexible generation.

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[31] Reverse load is where there is an injection of power at the lower voltage busbar of the transformer, and the level of station demand is insufficient to 'use up' this injection. As a result, the current will flow from the lower B/B to the higher voltage level.
[32] The connection may also have a firm element (their firm MEC)
[33] For the purpose of the Downward Flexibility Analysis based on Pilot 4, the estimated minimum load for a station is taken as 20% of the yearly max as a proxy for the summer valley load for that year. As SCADA load profiles are used in this assessment on some rare occasions the load is seen to be lower than this level.

- Where there is a transformer outage and the firm generation connected to the station is not generating at full output then the level of constraint of flexible generation may be reduced.
- Where there is a transformer outage and the load in the area is greater than minimum load then the level of constraint of flexible generation may be reduced

The assessment undertaken used average output from generation in the four areas in question. The assessment then compared the average output of flexible generation connections against the likely spare capacity to accommodate the firm generation in the area.

Example 1: if there was 10MW of wind generation in an area, and it was connected on a firm basis -

- Average output = 10MW*.35[34] = 3.5MW. So, on average, and at minimum load, there is 6.5MW of capacity which could be utilised by a flexible generation connection even if there was a transformer outage. Where the load at the station is greater than minimum load, this will further increase the capacity available to be utilised by the flexible generator.

The exception to this is where the load drops below the calculated min load level. In such a scenario, there may not be capacity available. So, a level of constraint was identified which is based on:

- The number of hours load is below the calculated minimum multiplied by
- The probability of a planned or forced transformer outage.

In undertaking the analysis based on the capacity factor of the generation, ESB Networks acknowledges that there is a level of inaccuracy. For example, a transformer fault could occur when the firm generation is exporting at greater than the average level, thereby reducing the scope for flexible generation output. Similarly, where the firm generation output is less than average, there would be additional capacity available for the flexible generator.

Overall, the level of inaccuracy is not deemed to be significant for the following reasons:

- Transformer outages are not common thereby reducing the risk of constraint significantly.
- Based on an analysis of ten operational windfarms, output is less than average MEC approximately 60% of the year.

<u>Output of Analysis</u>

The analysis undertaken of the four Pilot 4 stations indicated that the expected constraint is negligible (totalling 1.38MWh across 2025). While this low level of constraint has been borne out by the connected Pilot 4 solar generator (no need to constrain based on >12 months

[34] Capacity factor for wind over the course of the year is estimated at approximately 35%.

operation; approximately 483MWh of energy generated in 2025 by the 2MW of flexible generation) it is important to note the following:

1. This does not mean that these generators can be offered firm connections as their ability to be flexible is very important in ensuring the safety and security of the system.

2. This also does not mean that these generators will never be constrained as system conditions may well occur that are outside the scope of the study undertaken.

<u>Downward Flexibility Needs up to 2030</u>

The option of availing of a flexible generation connection is still available to customers and all applications which are submitted through the Enduring Connection Process (ECP), are assessed to determine whether a flexible connection may be of value to the customer and with a view to maximising the connection of renewable energy. While it is not currently possible to predict the locations at which applications may be made or where such applications may benefit from a flexible connection, it is reasonable to assume that there will not be a significant increase in the likely constraint of any such generation prior to 2030 such that the level of constraint might approach 10% of the overall island constraint level identified in Article 14 – Fine-tuning of system needs.

4.5.2 Microgeneration

Micro-generation is any generation which is <6kVa (when connected at single phase) or <11kVa (when connected at 3 phase). Typically, micro-generation is connected via domestic installations and is roof-top solar. Mini-generation can be up to 50kVa and (for example) can include connections at farms.

For the purposes of this assessment, all micro- and mini-generation is assumed to be solar. This is important as it feeds into the assessment in terms of times when generation output is to be expected. As outlined above, the constraint of micro-/mini-generation is assessed based on overloading of an MV/LV substation.

<u>Widespread Roll out of Microgeneration</u>

Over the last number of years there has been a significant uptake in domestic customers installing rooftop solar. This has been caused by a number of factors:

- The cost of installing solar panels has reduced significantly.
- There is now a feed-in tariff available to customers to pay for any energy exported.
- Recent conflicts in Ukraine and the Middle East have caused increases in the price of electricity and energy more generally reducing the likely payback time on any capital investment

As a result, by end 2025:

- There were approximately 170,000 micro- and mini-generation installations, totalling just over 800MW of generation.

- Approximately 70,000 MV/LV substations (from a population of approximately 280000) have micro-/mini-generation connected.

This extensive roll out meant that the exercise of comparing generation output against MV/LV substation capacity was challenging in terms of data analytics. This further meant that certain assumptions had to be adopted in the analysis.

Assumptions

The following assumptions were adopted:

Table 8: Downward Flexibility assessment – micro generation assumptions

Category	Assumption
Constraint Window	The need to constrain micro/mini-generation export is most likely to occur between April-September during the hours of 11am-2pm as this is when the solar output is highest and domestic load is frequently low (this represents approximately 540 hours per annum).
Solar Diversity	In line with the recent revision to the planning standards, a solar diversity factor of 0.78 is applied to the MEC.
LV Groups	Newer LV groups should have sufficient capacity[35], so focus is on older groups.
	Where the number of demand customers at a MV/LV substation is <= max allowable number[36], no constraint requirement is calculated.
Demand	Minimum demand during the hours of expected solar output is estimated at 500W per domestic connection.
MV/LV Substation Capacity	Assumed to be 100% of nameplate rating.

[35] Since 2020, LV groups have been designed with a higher After Diversity Maximum Demand (ADMD) of 5.5MVA. This was deemed appropriate to allow for new technology such as such as electric vehicles; heat pumps; photo-voltaic installations.
[36] The maximum permissible number of customer connections allowed to a new or existing transformer based on the transformer rating, as specified in the LV design standard.

Turn Down Rule	On a per substation basis, the output from micro-/mini-generation may need to be reduced if the expected output from the same is > (substation capacity +min demand).

Methodology

Population of MV/LV Substations to be Assessed:

The first step was to identify the MV/LV substations (from the full population or approximately 280,000) with micro-/mini-generation installed. As noted above, this identified approximately 70,000 MV/LV substations. There were also several other MV/LV substations which were removed prior to assessment. These are listed below.

Table 9: Substations removed prior to assessment

Category	Reason
Customer with an MEC = 0	No ability to export and as such cannot contribute to transformer overload.
Customers on the DG7 tariff	These customers are connected at MV and therefore will not impact MV/LV substation loading.
Substation size<15kVa	Should be replaced with 15kVA transformers in future. In addition, overall combined connected MEC of approximately 8 MVA (or <1% of total installed capacity of micro-mini generation for end of 2025) is negligible.
Transformers with missing rating (kVA) data	Within the base dataset there are approximately 3600 substations where there is no transformer rating data. Of this group there are only a small number – 35 substations – where there are MEC connections in the micro-/mini-generation range. The total contribution from this group of 35 is approximately 0.6MVA. Without transformer rating information it is not possible to assess these substations. However, their

	impact on the overall outcome is deemed to be negligible.
Transformers that currently don't exceed their maximum number of allowable demand connections	It is assumed that any additional connections to these transformers will align with the 2040 net zero Low Carbon Technology (LCT) ready scenario.

Base Case (2025):

The basic principle – as per the 'turn down rule' stated above - is to compare the demand at a given substation against the likely solar production. While this concept is simple the challenge is in the volume.

The key data required to complete the analysis on each individual MV/LV substation was:

1. Substation rating
2. Number of domestic or small commercial customers (demand) connected to that substation
3. Number of domestic or small commercial customers with an MEC at that substation
4. Using bullet 3 above and each customer individual MEC, aggregate MEC at the substation

This allowed a calculation at each substation as follows:

- Min demand at time of solar production = number of domestic or small commercial customers [37] *0.5kW.
- Solar production = Aggregate MEC*diversity factor.

Quantum of constraint estimated at each MV/LV substation:

- Transformer capacity + Min demand – Solar Production.

Where the result is negative, the need to constrain exists.

Growth of Microgeneration

The previous section sets out the assessment required to identify constraint based on the known level and (electrical) location of micro-/mini-generation end 2025. To assess likely constraint in 2028 and 2030 (target years for FNA), the growth rate of micro-/mini-generation installations, and the location of the new installations must be forecast.

[37] All customers – both domestic and small commercial – are assumed to have the same minimum demand.

Growth Rate:

The growth rate of microgeneration is in line with that agreed under PR6.

- Assumption 1: Using scenario 3 from the growth report, there is an expected installation in 2030 of 2.7GW.
- Assumption 2: For growth, all new installations were assumed to be microgeneration with an average size of 5kW.
- Assumption 3: Growth will be evenly distributed across each year from 2025 to 2030 resulting in an annual growth rate of 26.3%.
- Assumption 4: When calculating the number of new MEC connections we assume that the number of MEC connections on an existing transformer will not exceed the current number of MIC connections on that transformer.

Based on assumptions above, Table 10 sets out the forecast roll out of micro-/mini-generation installations.

Table 10: Forecast growth in Micro-/mini-generation installations

Year	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Total MEC Connections	173084	218605	276098	348712	440423	556254
Change in number of MEC Connections year on year	0	45521	57493	72614	91711	115831

Locations Assumed:

It is difficult to estimate with a level of certainty where the new micro-generation will be installed. However, some key assumptions and their impact are listed in Table 11.

Table 11: Key assumptions for micro-generation assessment

Assumption	**Impact**
Micro-generation was assumed to be connected to existing MV/LV substations.	Where micro-generation is connected to a new substation, the revision in substation standards (to cater for LCT connections) would mean that no constraint would be required. As a result, this assumption could drive a higher level of nationwide constraint.
MV/LV substation size (and number of connected customer) remains as 2025.	There is a programme of work to increase MV/LV substation sizes where required and/or

	to split LV groups such that there are less customers fed from a given MV/LV substation. As a result, this assumption could drive a higher level of nationwide constraint.
Minimum load being used at times of high solar output is considered to increase over the 5-year period (5.2% per annum).	5.2% growth rate is based on the most aggressive scenario. While this growth rate may be achieved in some areas as customers electrify more of their energy, where this level of growth is not achieved, further constraint may be necessary. As a result, this assumption could drive a lower level of nationwide constraint.

Having established the number of new micro-/mini-generation installations each year and the above principles, the micro-/mini-generation installations are distributed across 110kV stations based on two weightings:

- Growth rate of MEC connections per 110kV station. The 110kV stations with the highest growth rate will get a higher proportion of new installations.
- Percent of installations at the 110kV station compared with the total installations nationwide. The 110kV stations with the highest % of installations will get a higher proportion of new installations.

Once the number of installations per 110kV station has been established, the micro/mini-generation installations are distributed across all of the MV/LV substations at that 110kV substation based on the MV/LV substation size, and the % of a given transformer size compared with the total number of MV/LV substations at that 110kV substation.

Part B: Flexibility Needs Estimates

5. System Level Needs

This section outlines the TSO-identified system level flexibility needs developed in accordance with the methodology described in the Methodology chapter. It presents both the analytical findings and guidance on how to interpret them. Across this section, results for all weather scenarios and target years are presented where this can be done clearly and legibly. Where outputs involve detailed graphs or extensive numerical data that cannot be presented clearly across multiple scenarios and target years, results are shown for a single representative weather scenario for each target year (Weather Scenario 28). Weather Scenario 28 was selected as broadly representative of the average outcomes across the weather scenarios assessed. The full set of results is provided in the appendices.

5.1 RES integration needs

This section covers the results of the analysis of the RES integration flexibility needs, which refers to the quantity of flexibility required for Ireland to achieve its annual RES integration targets.

5.1.1 RES generation curtailment time series

Figures 3 and 4 provide a representation of the RES generation curtailment time series extracted from the FNA model for 2028 and 2030. These results represent the total dispatch down of RES, including an element which is produced by the model which has the impact of ramping and short-term flexibility included and therefore represents surplus and curtailment drivers, and where the impact of RES dispatch down from transmission network flexibility needs (i.e. constraint drivers) have been added through the fine-tuning process. These are a representation of the main output from the models following the FNA methodology which is used to calculate the results in the remaining sections.

These results have been produced in line with the ACER Methodology Articles 8 (1), 8 (2) and 8 (3).

Figure 3: RES generation curtailment time series, hourly percentage throughout the year, 2028, WS28 – Article 8(1)

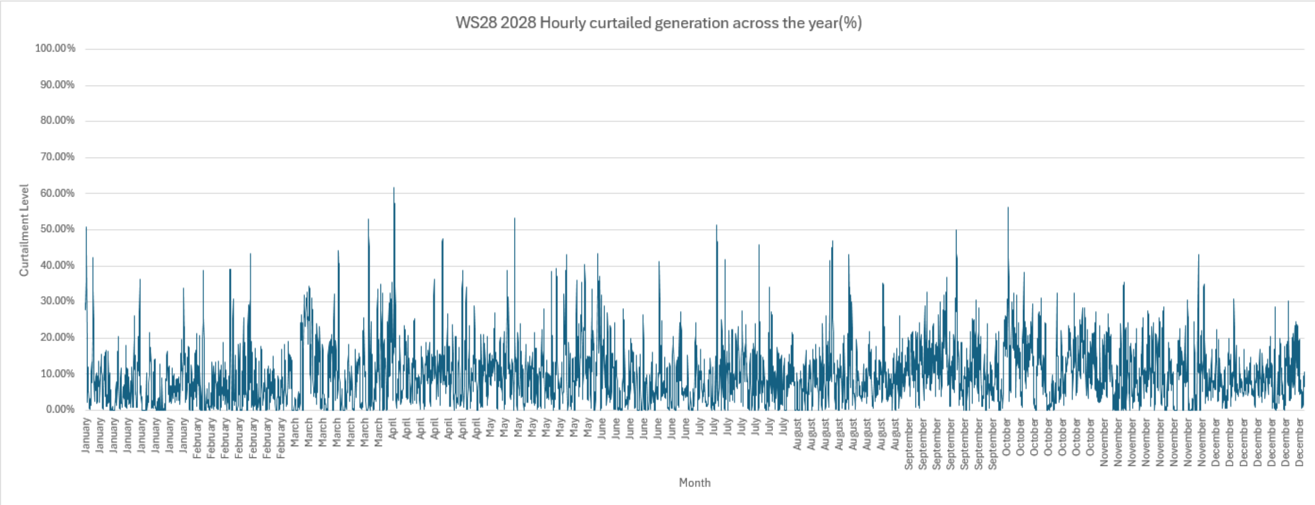
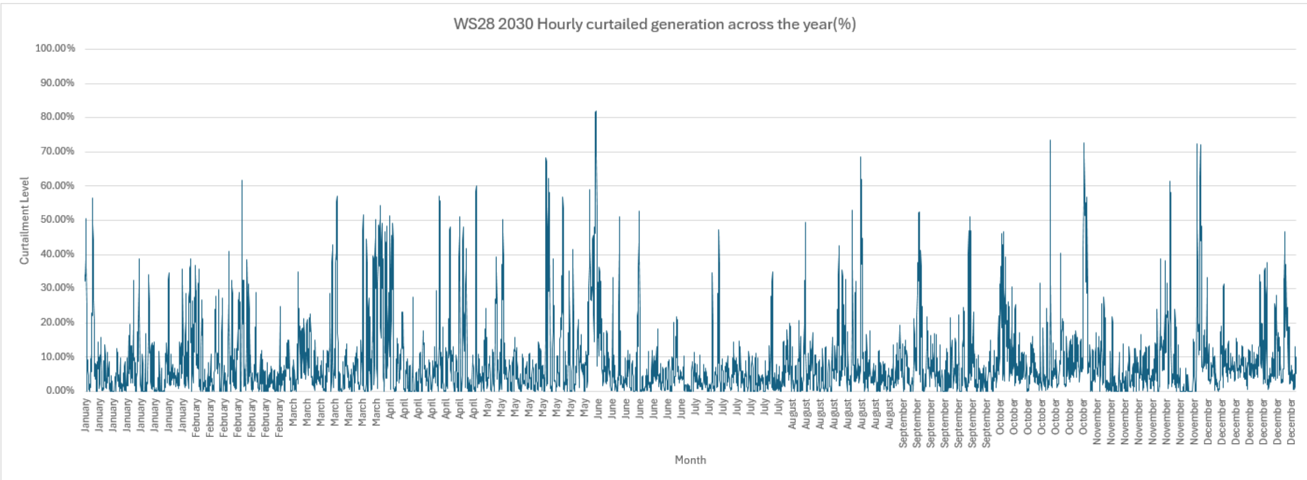


Figure 4: RES generation curtailment time series, hourly percentage throughout the year, 2030, WS28 – Article 8(1)



Figures 3 and 4 show that RES generation curtailment occurs mostly in shoulder months, and that there are larger peaks in RES generation curtailment in 2030 than 2028 as the level of installed RES capacity increases.

RES generation curtailment – average, maximum and minimum values

Figures 5 and 6 provide the visualisation of weekly, monthly and annual curtailed RES generation, in the form of average, maximum and minimum values.

How to interpret these figures:

- Average RES generation curtailment values are represented as solid lines. These are the average of all hours for the particular period.

- Maximum values are represented as dotted lines. These are the maximum RES generation curtailment values that occurred in the particular period.
- Minimum values are nearly always 0, as for any week or month or throughout the whole year there are hours with no curtailment. However, there are a small number of weeks where there was a non-zero minimum level of RES generation curtailment, reflecting long periods of continuous RES dispatch down.

These results have been produced in line with the ACER Methodology Article 8(4)(a).

Figure 5: Weekly, monthly and annual curtailed generation (average, maximum and minimum values), 2028, WS28, Article 8(4)(a)

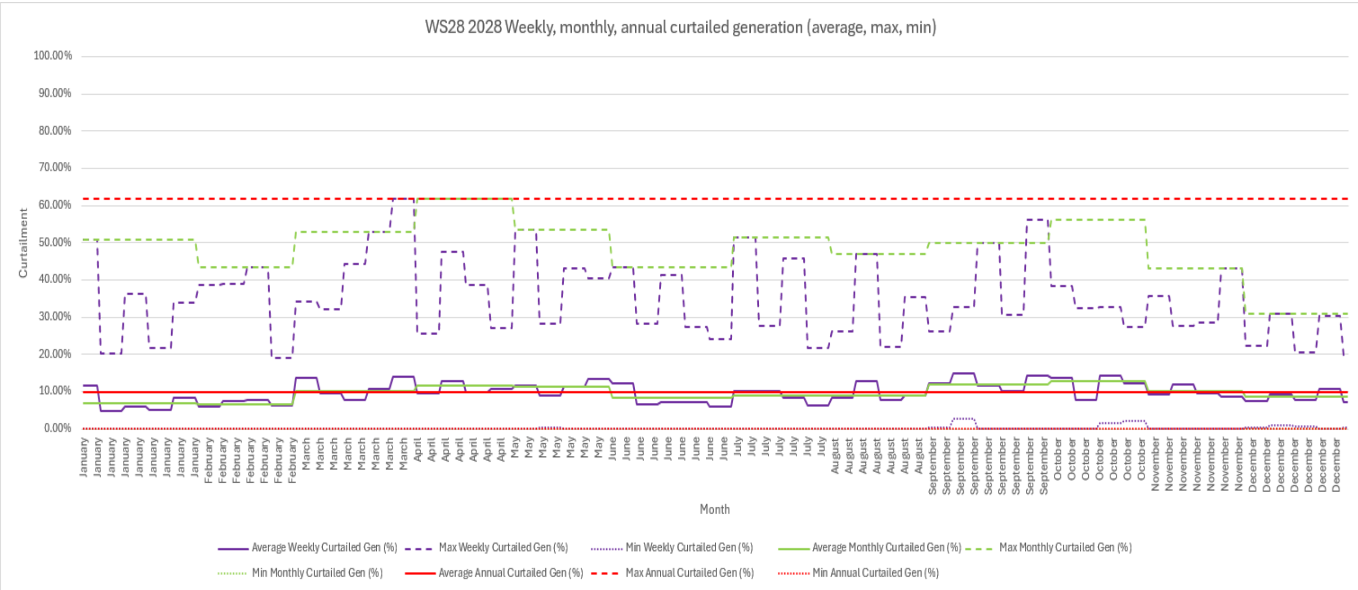
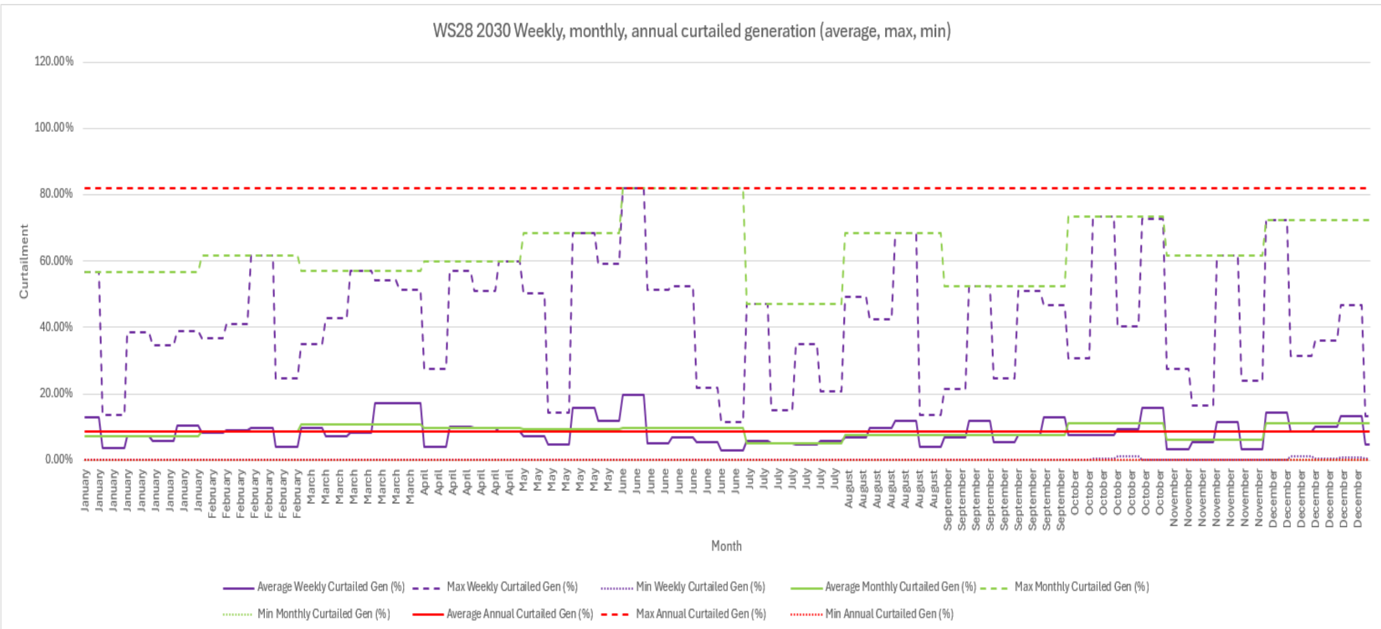


Figure 6: Weekly, monthly and annual curtailed generation (average, maximum and minimum values), 2030, WS28, Article 8(4)(a)



These results can provide some insights into the potential quantities of flexibility, as a percentage of VRES availability, that would be required to eradicate RES generation curtailment on hourly, weekly, and monthly timeframes, and the level of effectiveness they might have over various periods of time. Shorter duration flexibility could therefore be aligned with the maximum needs in shorter duration periods and align longer duration flexibility with the average needs in longer duration periods. For example, if 50% of the VRES power availability quantity were to be developed as flexible capacity with week-long energy duration, that would be sufficient to eradicate RES generation curtailment for all weeks where the purple dotted line (maximum) is less than 50% on the y-axis. However, if the purple solid line (average) is consistently much lower than that maximum then that level of flexible capacity may not be effectively used over all periods of time. Similarly, if 10% of VRES power availability quantity were to be developed as flexible capacity with week-long duration, that would be sufficient to eradicate RES generation curtailment for all weeks where the purple solid line (average) is less than 10% on the y-axis. However, if the purple dotted line (maximum) is much higher than that value then that level of flexible capacity would not be able to eradicate RES generation curtailment in those particular maximum MW periods.

WS28 2028:

Based on the explanation above, figure 5 indicates that the capacity of flexibility that would be required in power terms to eradicate curtailment in the relevant timescales would be:

- Approximately 60 % of total wind and solar power availability for hour-long flexibility, corresponding to the maximum RES generation curtailment as shown on the graph.
- Approximately 15 % of total wind and solar power availability for week-long flexibility, corresponding to the maximum weekly average RES generation curtailment as shown on the graph.
- Approximately 13 % of total wind and solar power availability for month-long flexibility, corresponding to the maximum monthly average RES generation curtailment as shown on the graph.

WS28 2030**:**

Figure 6 indicates that the capacity of flexibility that would be required in power terms to be able to eradicate RES generation curtailment in the relevant timescales would be:

- Approximately 82 % of total wind and solar power availability for hour-long flexibility, corresponding to the maximum RES generation curtailment as shown on the graph.
- Approximately 20 % of total wind and solar power availability for week-long flexibility, corresponding to the maximum weekly average RES generation curtailment as shown on the graph.
- Approximately 11 % of total wind and solar power availability for month-long flexibility, corresponding to maximum monthly average RES generation curtailment as shown on the graph.

RES generation curtailment – probability distribution

The following tables and graphs summarise the probability distribution of RES generation curtailment annually, i.e. over an annual period there are a given number of hours where curtailment at a certain %. These results have been produced in line with the ACER Methodology Article 8(4)(b), outlining the probabilities of different levels of RES generation curtailment arising in the annual results for each target year and weather scenario. The results show that the probability of RES generation curtailment less than 1% (including 0%) is generally less than the probability of RES generation curtailment between 1% and 11%, which represents the most likely outcome across both target years. In 2028 the probability of between 11% and 20% RES generation curtailment is the next highest, while in 2030 the probability of this level of RES generation curtailment is slightly less than the probability of less than 1% curtailment. The probability of RES generation curtailment levels above 20% then starts to diminish as the level of RES generation curtailment increases.

Table 12: Curtailment probability distribution chart for different FNA scenarios - Article 8(4).

	Probability					
	WS28		WS4		WS34	
Curtailment	2028	2030	2028	2030	2028	2030
<1%	9.6%	13.9%	9.9%	13.9%	9.8%	14.0%
1%-11%	55.6%	64.5%	55.2%	65.2%	55.6%	63.8%
11%-20%	26.6%	11.8%	25.9%	11.6%	26.5%	11.9%
20%-30%	6.2%	4.3%	6.5%	4.0%	5.9%	4.4%
30%-40%	1.4%	2.8%	1.8%	2.8%	1.5%	2.9%
40%-49%	0.5%	1.7%	0.7%	1.4%	0.6%	1.6%
50%-100%	0.1%	1.0%	0.1%	1.0%	0.1%	1.3%

The following graphs provide the occurrence distribution for different level of RES generation curtailment. Since for many periods of time there is no RES generation curtailment, for both target years two graphs are presented, the first including zero percent RES generation curtailment, and the second starting from 1% RES generation curtailment.

Figure 7: Hourly curtailment distribution chart, 2028, WS28 – Article 8(4)(b)

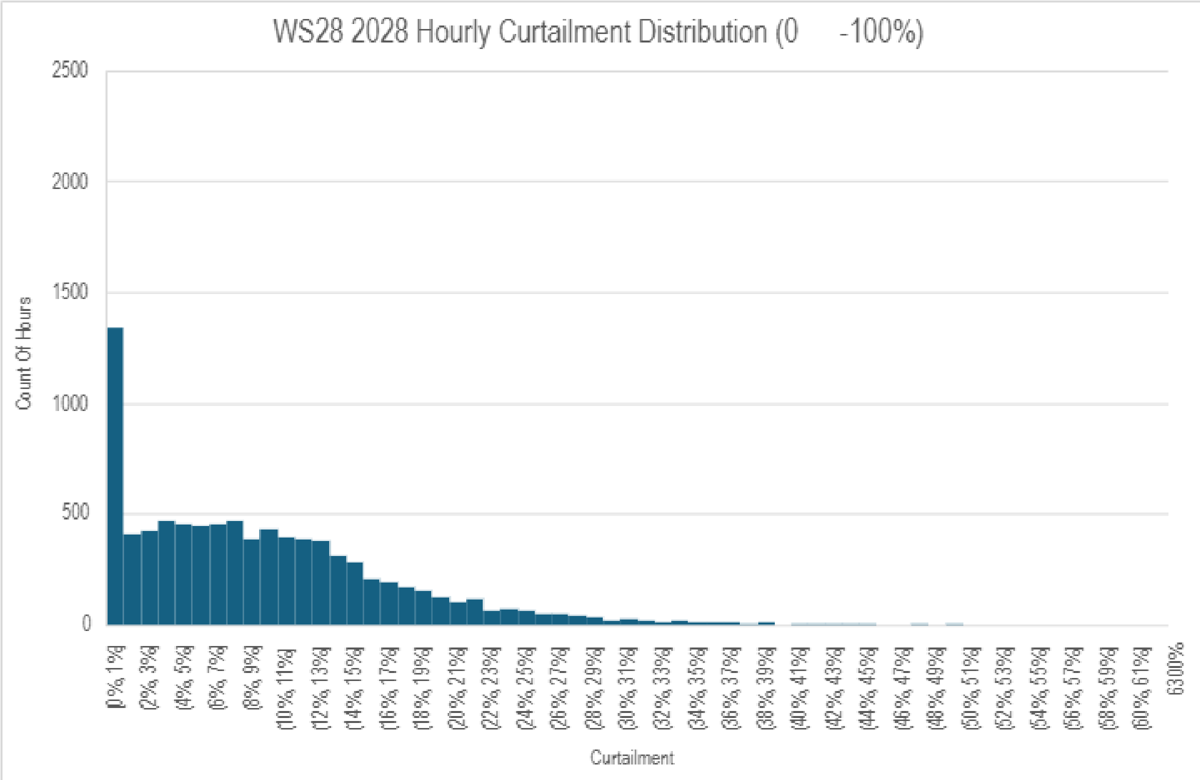


Figure 8: Hourly curtailment distribution chart, 2028, WS28 – Article 8(4)(b)

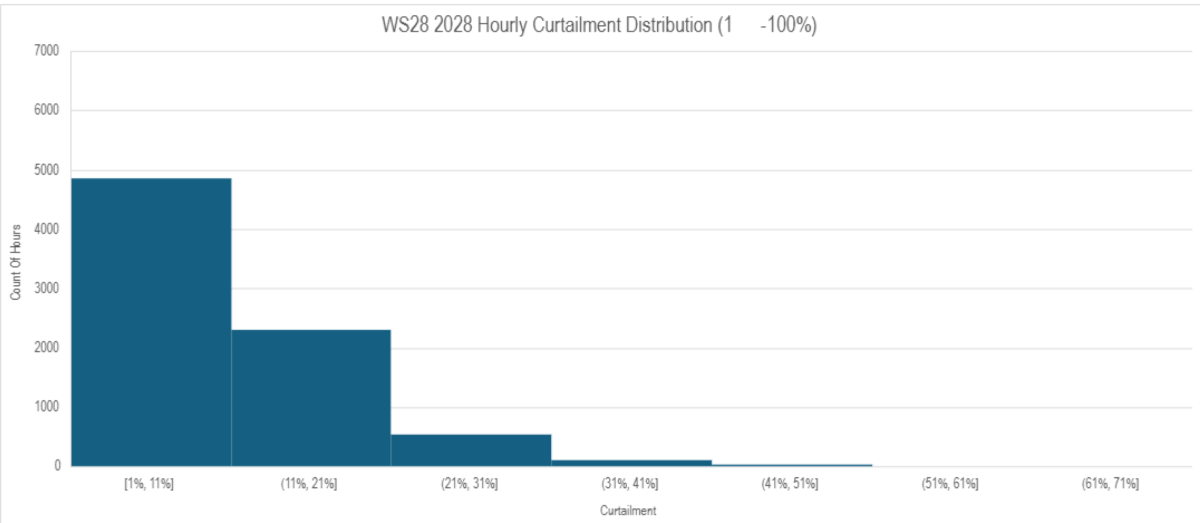


Figure 9: Hourly curtailment distribution chart, 2030, WS28 – Article 8(4)(b)

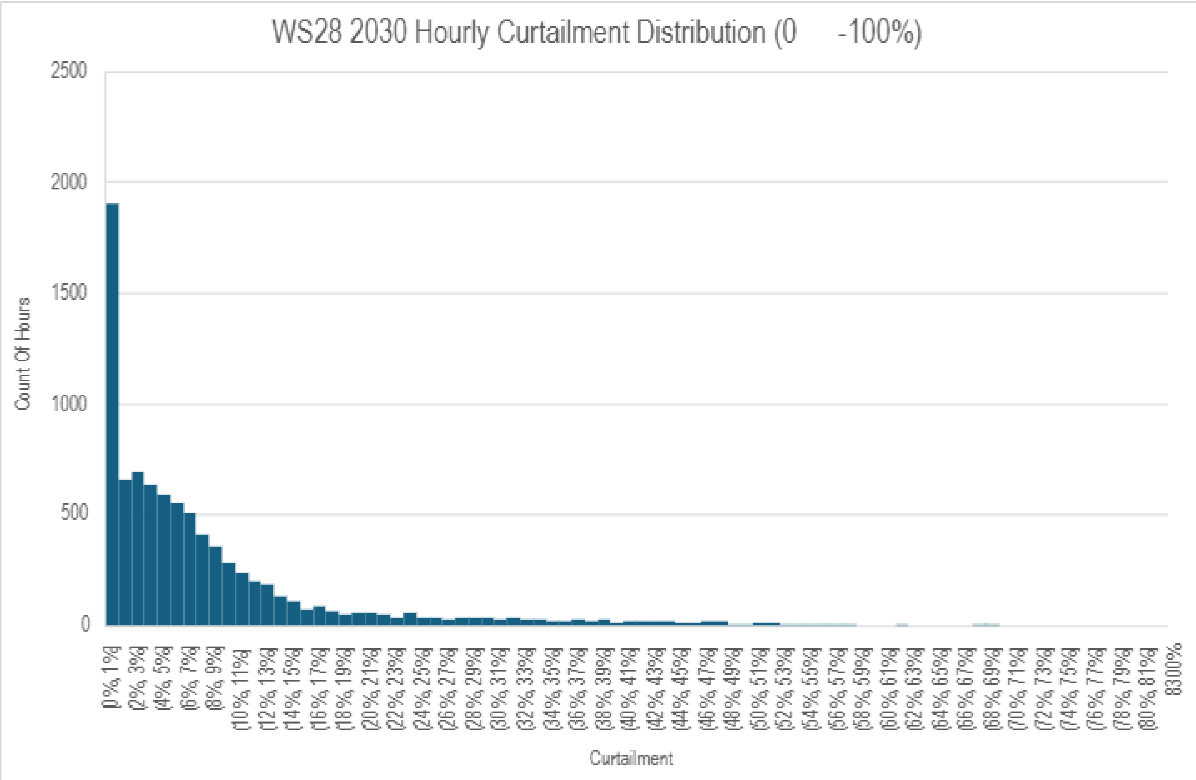


Figure 10: Hourly curtailment distribution chart, 2030, WS28 – Article 8(4)(b)

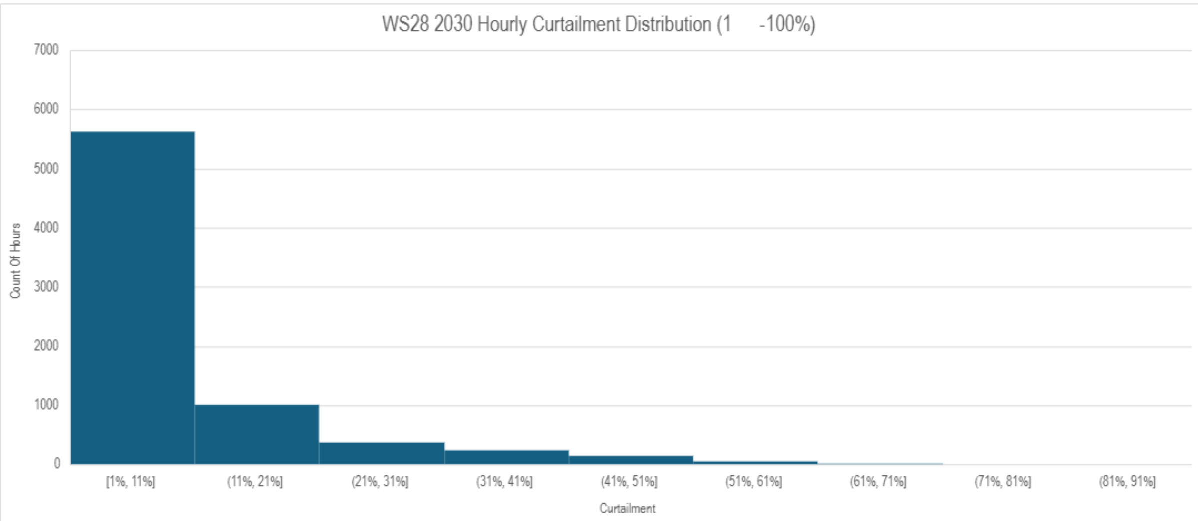


Table 12 and Figures 7,8,9 and 10 show that in a large proportion of the time (between 9.6% and 14% depending on year and scenario) RES generation curtailment is less than 1%, while for a very small proportion of the time (0.1% to 1.3%) RES curtailment is between 50% and 100%. This means that although flexibility with large capacity would be required for shorter durations to completely remove curtailment when RES generation curtailment is high, a smaller capacity of flexibility that could cover a longer period of time during which there is a smaller level of dispatch down would need to be used approximately 90% of the time.

The following tables and graphs extend this probability distribution analysis looking at daily, weekly, and monthly averages:

Table 13: Daily average curtailment distribution across all weather scenarios - Article 8(4)(b)

WS28				WS4				WS34			
2028		2030		2028		2030		2028		2030	
Curtailment	**Probability**	**Curtailment**	**Probability**	**Curtailment**	**Probability**	**Curtailment**	**Probability**	**Curtailment**	**Probability**	**Curtailment**	**Probability**
0%-5%	15.9%	0%-10%	73.4%	0%-5%	15.7%	0%-10%	76.1%	0%-5%	19.5%	0%-10%	75.8%
5%-10%	42.0%	10%-20%	18.7%	5%-10%	42.6%	10%-20%	16.8%	5%-10%	41.8%	10%-20%	14.0%
10%-15%	27.7%	20%-30%	5.8%	10%-15%	26.1%	20%-30%	5.8%	10%-15%	26.4%	20%-30%	8.2%
15%-20%	11.5%	30%-40%	1.6%	15%-20%	12.4%	30%-40%	0.8%	15%-20%	9.3%	30%-40%	0.5%
20%-25%	1.9%	40%-50%	0.0%	20%-25%	1.9%	40%-50%	0.3%	20%-25%	1.4%	40%-50%	1.4%
25%-30%	0.8%	50%-60%	0.5%	25%-30%	1.1%	50%-60%	0.3%	25%-30%	1.4%	50%-60%	0.0%
		60%-70%	0.0%	30%-35%	0.3%	60%-70%	0.0%	30%-35%	0.3%		
		70%-80%	0.0%			70%-80%	0.0%				
		80%-90%	0.0%			80%-90%	0.0%				

Figure 11: Daily average curtailment distribution, 2028, WS28 – Article 8(4)(b)

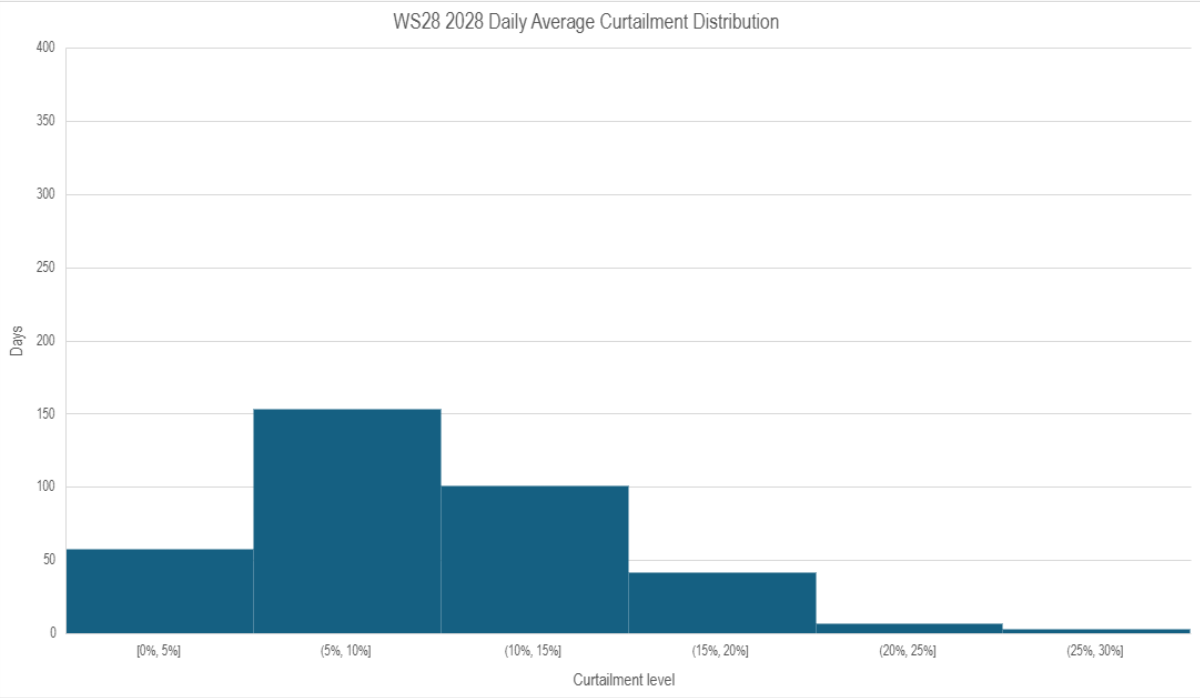


Figure 12: Daily average curtailment distribution, 2030, WS28 – Article 8(4)(b)

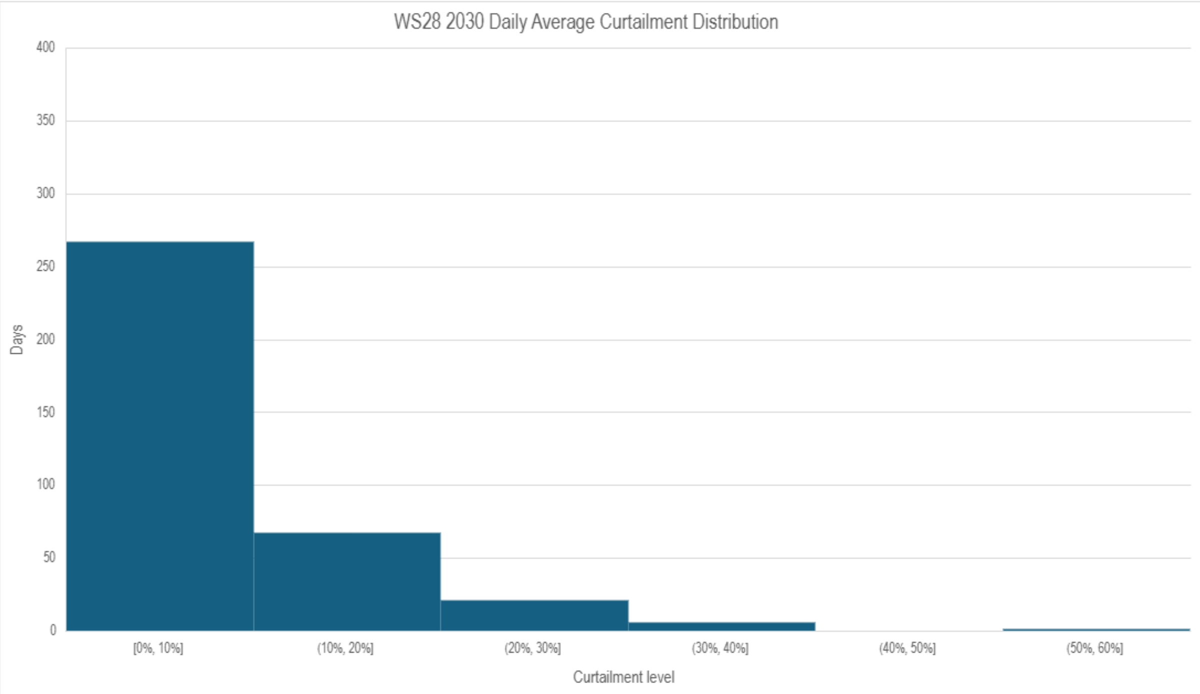


Table 14: Weekly average curtailment distribution across all weather scenarios - Article 8(4)(b)

WS28				WS4				WS34			
2028		2030		2028		2030		2028		2030	
Curtailment	Probability	Curtailment	Probability	Curtailment	Probability	Curtailment	Probability	Curtailment	Probability	Curtailment	Probability
5%-7%	15.1%	3%-7%	39.6%	5%-7%	18.9%	2%-6%	32.1%	4%-6%	11.3%	2%-6%	30.2%
7%-9%	26.4%	7%-11%	35.8%	7%-9%	24.5%	6%-10%	45.3%	6%-8%	22.6%	6%-10%	39.6%
9%-11%	26.4%	11%-15%	15.1%	9%-11%	26.4%	10%-14%	15.1%	8%-10%	26.4%	10%-14%	20.8%
11%-13%	17.0%	15%-19%	7.5%	11%-13%	13.2%	14%-18%	3.8%	10%-12%	20.8%	14%-18%	5.7%
13%-15%	13.2%	19%-23%	1.9%	13%-15%	11.3%	18%-22%	1.9%	12%-14%	9.4%	18%-22%	1.9%
15%-17%	1.9%			15%-17%	5.7%	22%-26%	1.9%	14%-16%	7.5%	22%-26%	1.9%
								16%-18%	1.9%		

Figure 13: Weekly average curtailment distribution, 2028, WS28 – Article 8(4)(b)

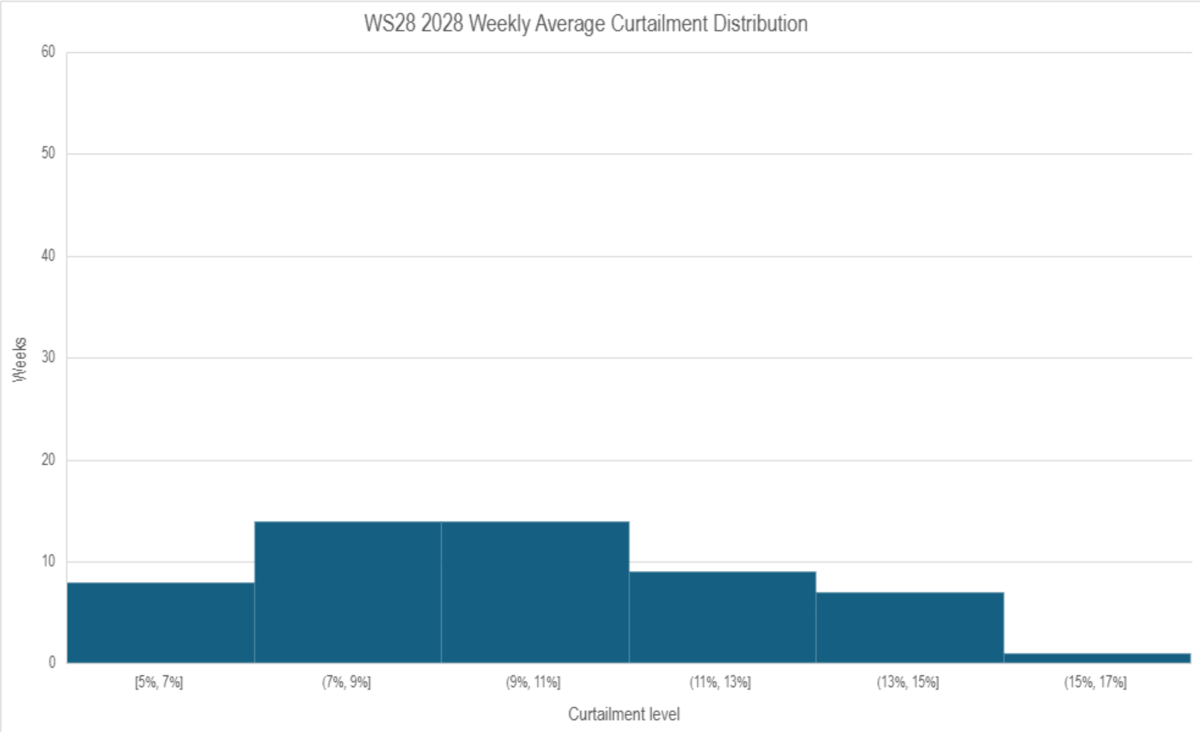


Figure 14: Weekly average curtailment distribution, 2030, WS28 – Article 8(4)(b)

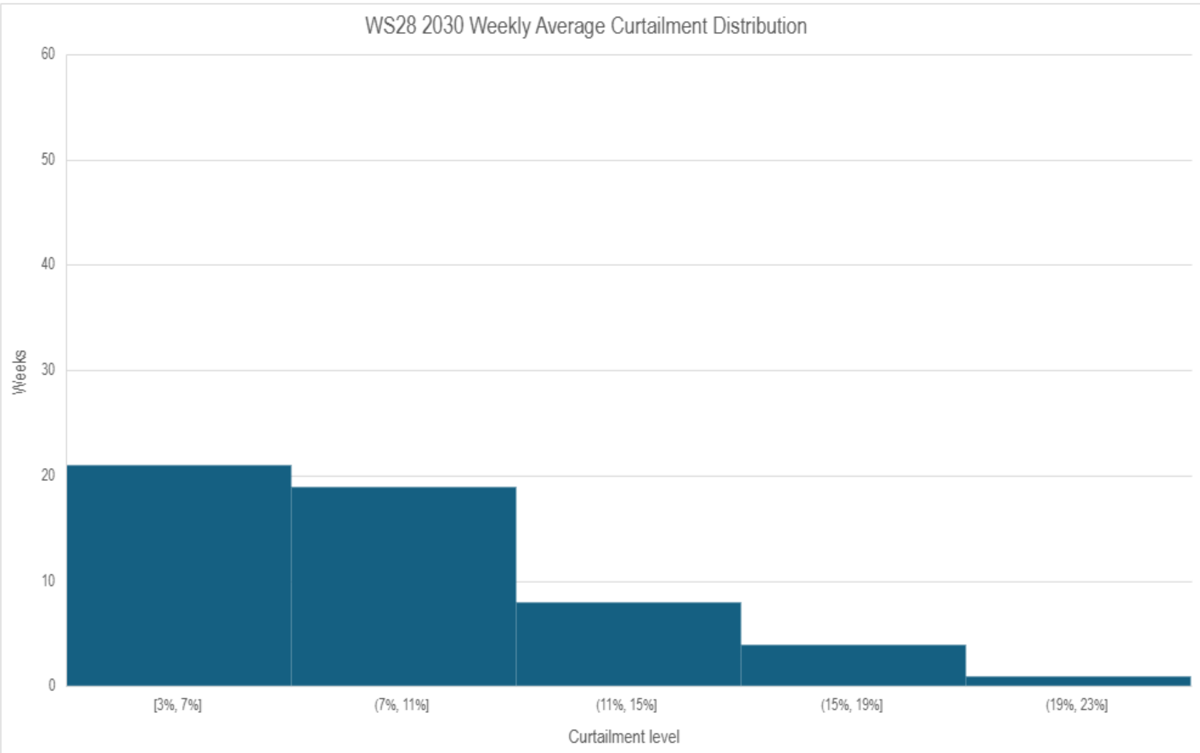


Table 15: Monthly average curtailment distribution across all weather scenarios - Article 8(4)(b)

WS28				WS4				WS34			
2028		2030		2028		2030		2028		2030	
Curtailment	**Probability**	**Curtailment**	**Probability**	**Curtailment**	**Probability**	**Curtailment**	**Probability**	**Curtailment**	**Probability**	**Curtailment**	**Probability**
7%-8%	16.7%	5%-6%	8.3%	6%-7%	8.3%	4%-5%	16.7%	6%-7%	16.7%	6%-7%	16.7%
8%-9%	16.7%	6%-7%	8.3%	7%-8%	8.3%	5%-6%	8.3%	7%-8%	0.0%	7%-8%	16.7%
9%-10%	16.7%	7%-8%	25.0%	8%-9%	25.0%	6%-7%	8.3%	8%-9%	33.3%	8%-9%	16.7%
10%-11%	16.7%	8%-9%	8.3%	9%-10%	8.3%	7%-8%	8.3%	9%-10%	0.0%	9%-10%	33.3%
11%-12%	16.7%	9%-10%	25.0%	10%-11%	8.3%	8%-9%	25.0%	10%-11%	25.0%	10%-11%	0.0%
12%-13%	16.7%	10%-11%	8.3%	11%-12%	16.7%	9%-10%	16.7%	11%-12%	8.3%	11%-12%	0.0%
13%-14%	0.0%	11%-12%	16.7%	12%-13%	16.7%	10%-11%	0.0%	12%-13%	16.7%	12%-13%	8.3%
				13%-14%	8.3%	11%-12%	0.0%			13%-14%	8.3%
						12%-13%	8.3%				
						13%-14%	8.3%				

Figure 15: Monthly average curtailment distribution, 2028, WS28 – Article 8(4)(b)

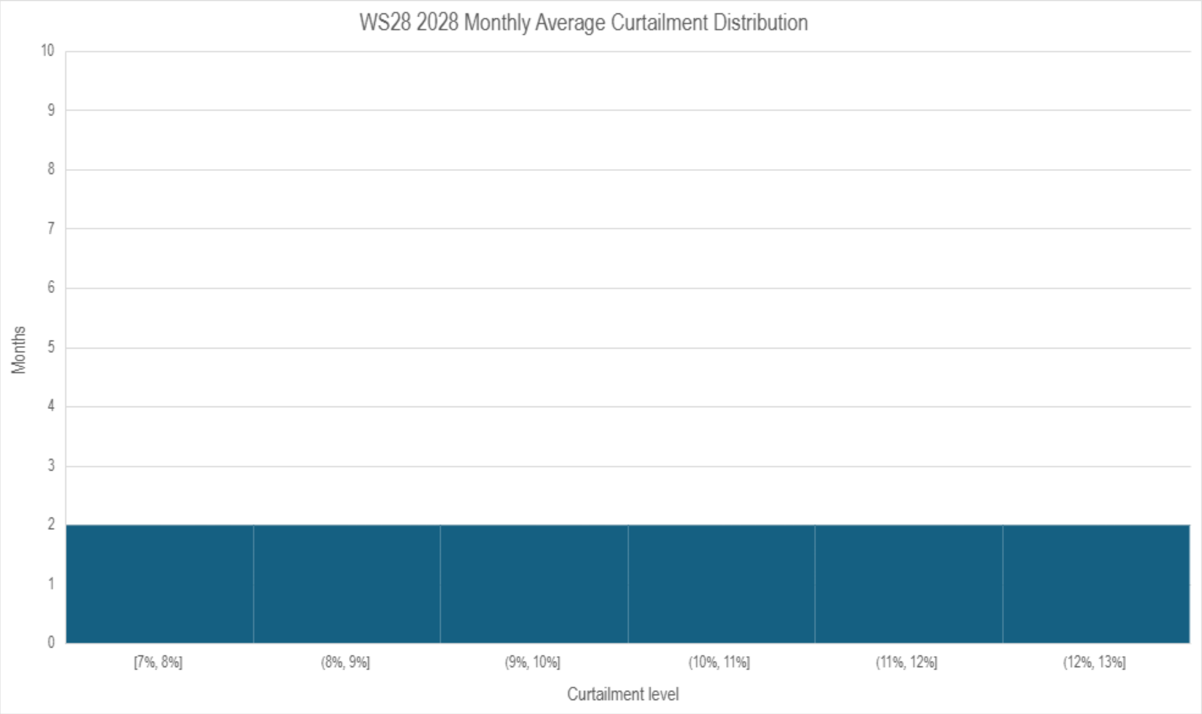
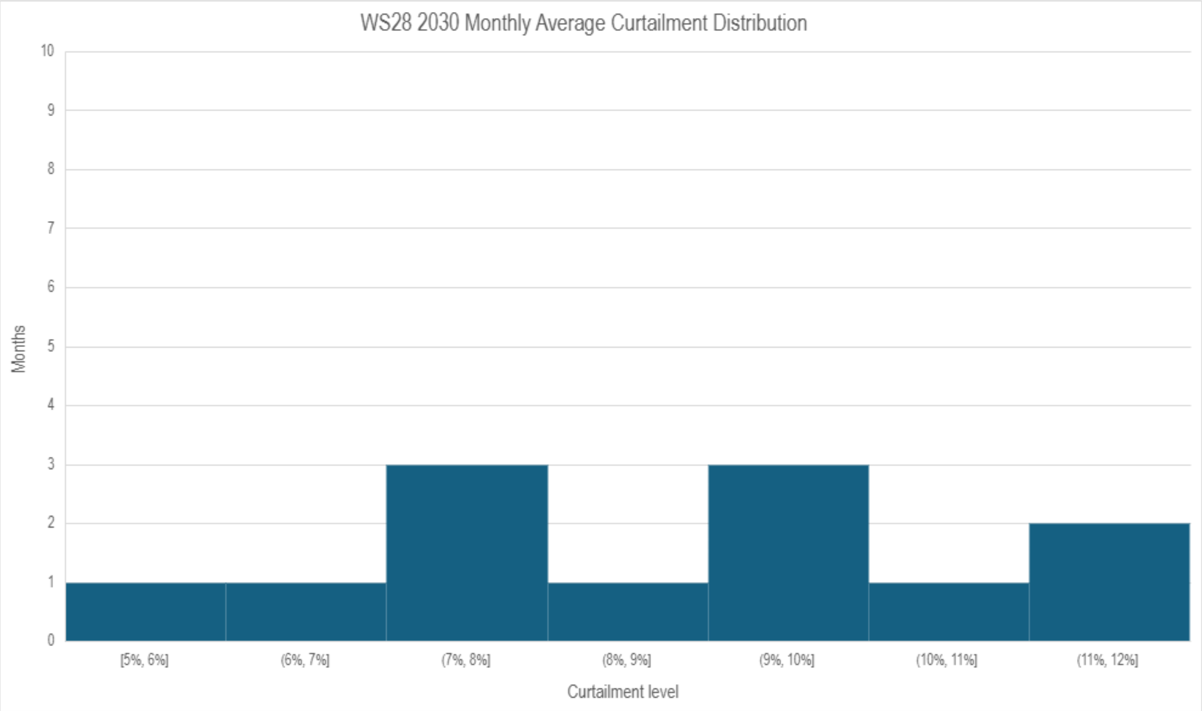


Figure 16: Monthly average curtailment distribution, 2030, WS28 – Article 8(4)(b)



2030 summary:

- The results for 2030 for daily and weekly averages show similar themes to those in the hourly distribution charts. There is a relatively larger proportion of time at lower levels of RES generation curtailment on average over these daily and weekly periods (e.g. up to 10% RES generation curtailment), less time at higher levels of RES generation curtailment on average over these daily and weekly periods (e.g. beyond 30% RES generation curtailment), but there is time at mid-level RES generation curtailment (i.e. 10%-30%) which would suggest that a somewhat smaller capacity of flexibility which can be used for longer periods of time would be needed to cover most dispatch down instances.

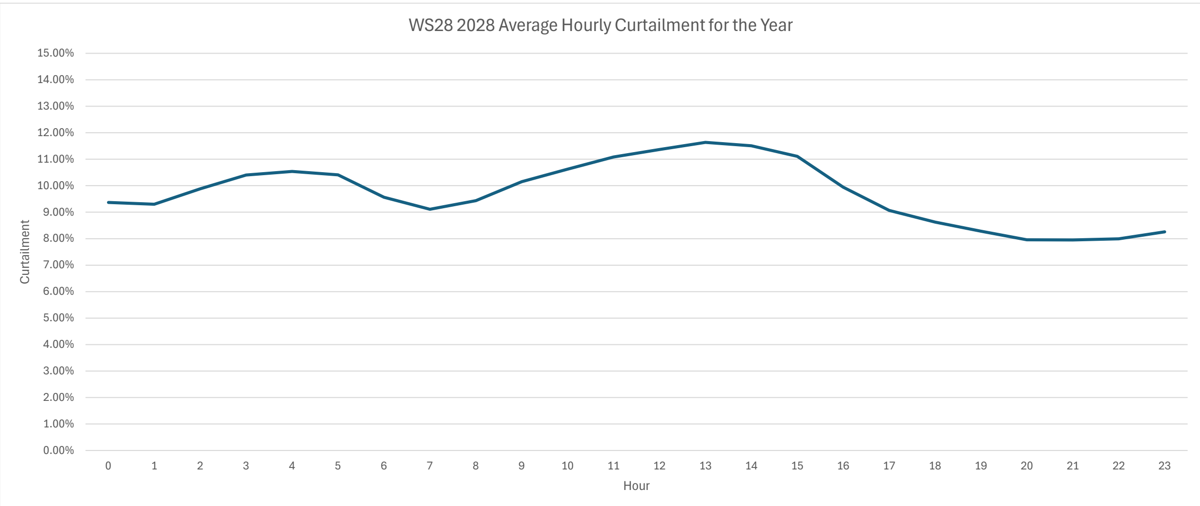
2028 summary:

- The results for 2028 show that there are more periods of time where the level of RES generation curtailment is concentrated around 5-15% rather than the majority being between 1 and 5% as in 2030. This potentially reflects a consistent level of dispatch down for transmission network reasons as highlighted in other results.

RES generation curtailment – representation as a function of time and day

Figure 17 presents the annual average of curtailment for each hour of the day for target year 2028.

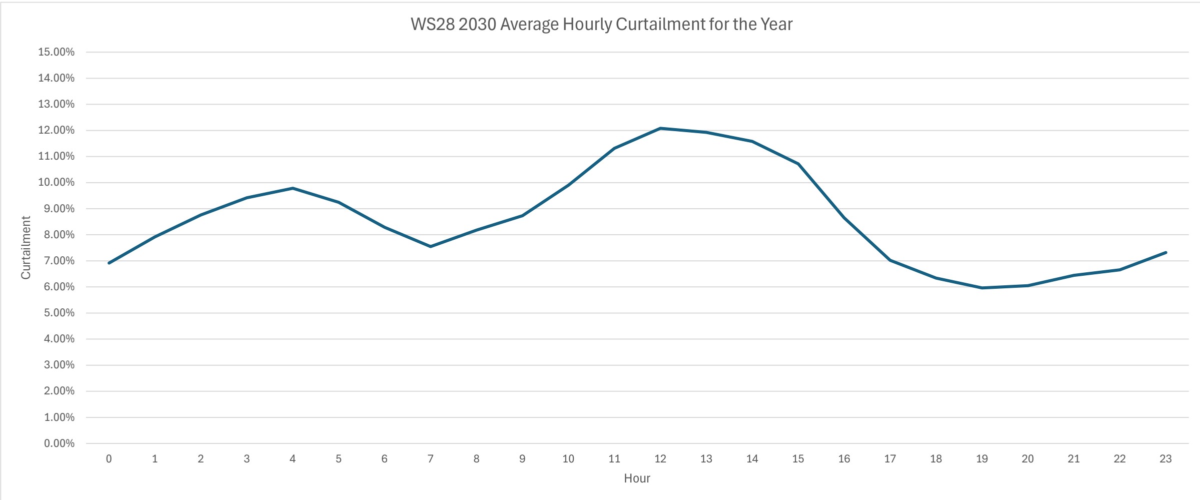
Figure 17: Average Hourly Curtailment for the Year, 2028, WS28 – Article 8(4)(c)



The average curtailment shows a double-peak characteristic, with approximately 10% at 2- and approximately 12% at 1pm. The lowest curtailment on average is approximately 8% at around 7-11pm. The graph is in line with the expectation that RES generation curtailment is somewhat inversely correlated to the average residual load curve. As shown in the graph RES generation curtailment is higher overnight where a combination of higher wind and lower demand may be expected. RES generation curtailment is somewhat consistent throughout the day reflecting the fact that curtailment of wind energy could arise at any time which is not necessarily the case for solar power. RES generation curtailment reduces in periods where demand is increasing, and finally curtailment increases during hours where solar power is highest.

Figure 18 presents the annual average of RES generation curtailment for each hour of the day for target year 2030.

Figure 18: Average Hourly Curtailment for the Year, 2030, WS28 – Article 8(4)(c)



The average RES generation curtailment again shows a double-peak characteristic, with approximately 10% at 4am and approximately 12% during 12:00-14:00. The lowest RES generation curtailment on average is approximately 6% at around 18:00-21:00. This shows similar characteristics to those in 2028, although the extent of the double peak characteristic, e.g. the differences between the peaks and the troughs, are greater in 2030 than in 2028. This likely reflects the growth in installed capacity for both wind and solar power sources in 2030 compared to 2028.

Figures 19 and 20 represent the same information but split out by month rather than an average for each hour over the whole year. These figures show RES generation curtailment as a function of time and day, where the average of RES generation curtailment for each hour of the day is calculated on a month-by-month basis, so that the average levels of RES generation curtailment in each hour in each month can be compared.

Figure 19: Average Hourly Curtailment per Month, 2028, WS28 – Article 8(4)(c)

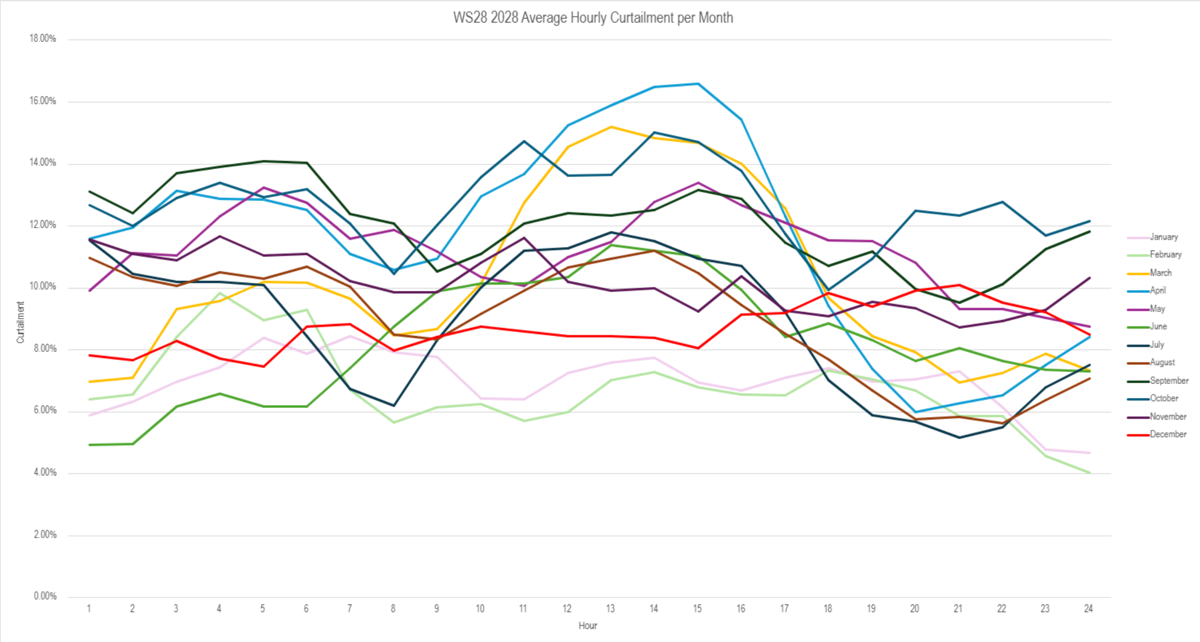
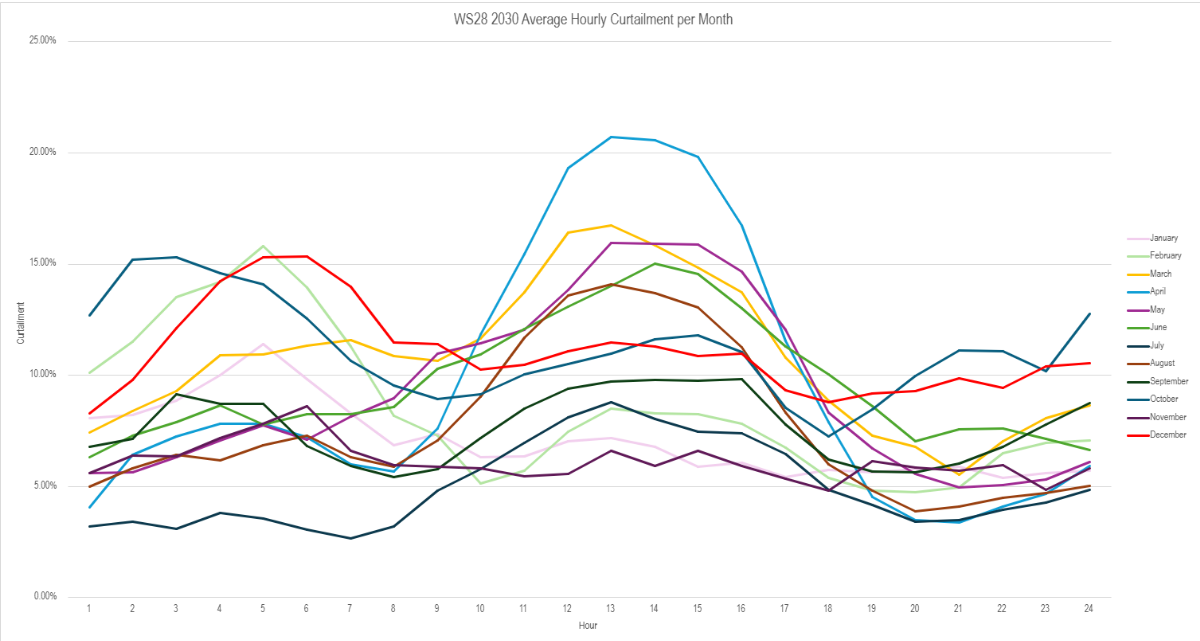


Figure 20: Average Hourly Curtailment per Month, 2030, WS28 – Article 8(4)(c)



These results show that April has the highest average hourly RES generation curtailment, which is 17% between 2-3pm in 2028 and 21% between 1-2pm in 2030. Summer months are more likely to experience curtailment around the early afternoon, whereas winter months are more likely to experience RES generation curtailment just before the early morning peak. The March data also evidences higher expected RES generation curtailment in both early morning and mid-afternoon timeframes. This may be down to a number of factors such as wind availability that is still high before the summer months, solar availability that is starting to increase coming into the summer months, and demand that is starting to decrease coming out of the winter months.

These results show that while the effect of solar power is more obvious in particular periods (especially in daylight periods in 2030 as installed solar capacity grows), the major influence on the levels of RES generation curtailment seems to be wind power (given the level of RES generation dispatch down across all periods, not just daylight periods correlating with solar). Load and solar power shapes are repeated and therefore their impact on the average hourly RES generation curtailment is relatively consistent. The wind power shape is variable such that it can occur in any period of the year, although there would tend to be higher levels of RES generation curtailment in periods with lower levels of demand and at times of year where the level of wind availability is greater on average such as over winter months.

These graphs also seem to indicate that there is rise in RES generation curtailment just prior to a drop in RES generation curtailment over the morning peak and evening peak. This may be driven by scheduling in the model of conventional units in preparation for these peak periods. In order to meet residual load ramps, in particular in models which have operational constraints that require conventional generation to be on the system, such conventional generators would be started up earlier to ensure they are available to meet that ramping requirement, which may result in an increase in RES generation curtailment to make room for that conventional generator's energy.

These graphs also provide some indications of the expected operation and arbitrage potential of flexibility for eradicating RES generation curtailment alone. To minimise RES generation curtailment, some forms of flexibility may need to be able to operate at least once and maybe twice a day, as a minimum (not average), to be able to pick up on those peak periods, which would need to be considered if the flexibility has an energy limit. However, there is also a consistent level of curtailment over all periods of time which may make it difficult for some flexible resources to offload their stored energy in that consistent manner. The graphs also show that peak RES generation curtailment varies significantly by month. This variation would need to be considered when determining the capacity of flexibility resources required to reduce RES generation curtailment and how those resources would be utilised throughout the year. For example, higher-capacity resources may be needed to address peak RES generation curtailment periods but could be underutilised at other times of the year, whereas lower-capacity resources may be sufficient for most months but may not be capable of addressing the highest RES generation curtailment peaks.

RES generation curtailment – correlation

Figures 21, 22, 23 and 24 provide a visualisation of the correlation between RES generation curtailment and wind, solar and native load. Two graphs are provided for each year, one for weekly and monthly average respectively.

Figure 21: Average weekly RES generation curtailment vs wind, solar, native load, 2028, WS28 – Article 8(4)(d)

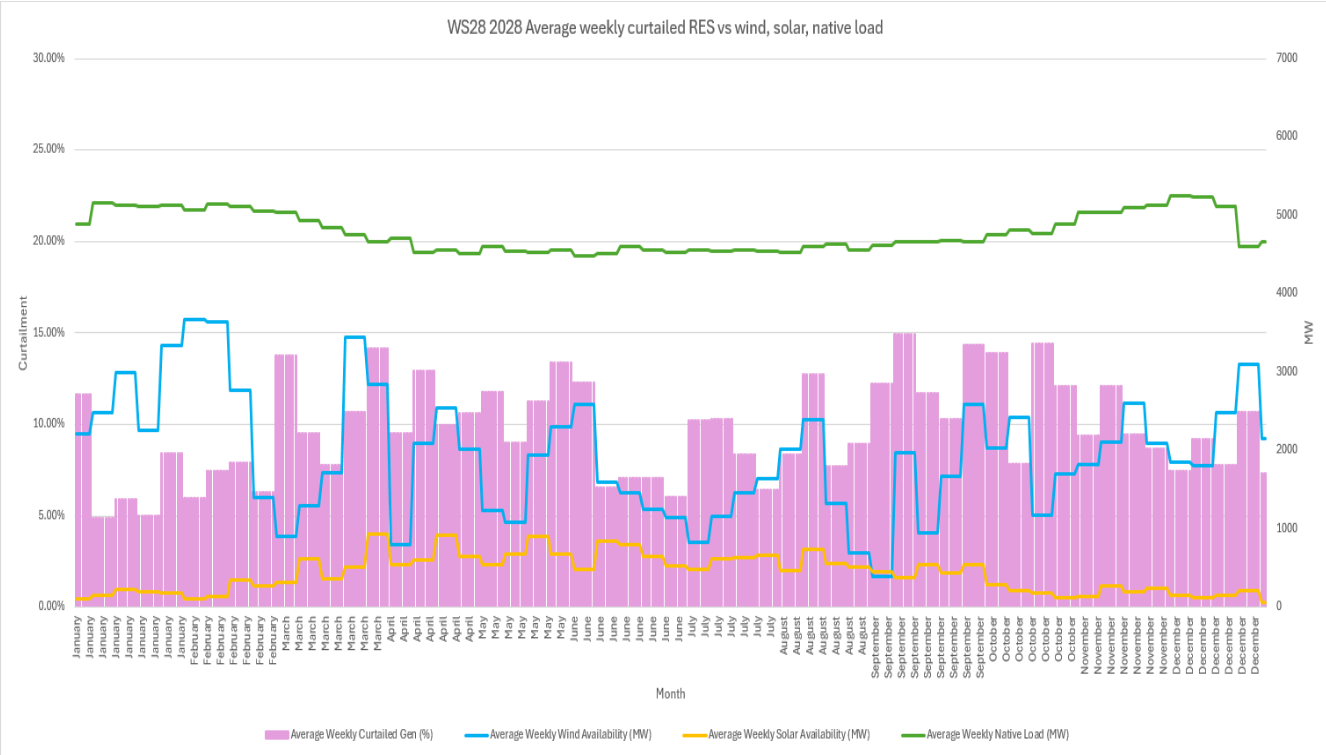


Figure 22: Average monthly RES generation curtailment vs wind, solar, native load, 2028, WS28 – Article 8(4)(d)

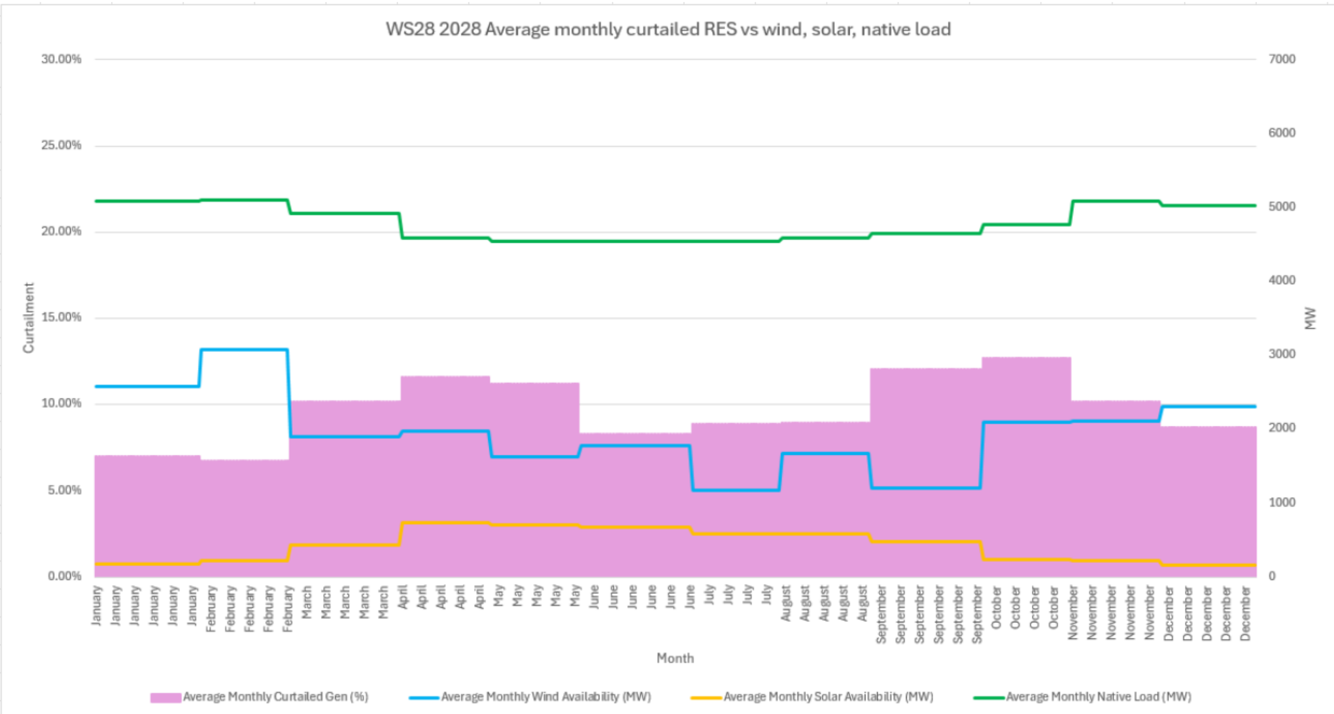


Figure 23: Average weekly RES generation curtailment vs wind, solar, native load, 2030, WS28 – Article 8(4)(d)

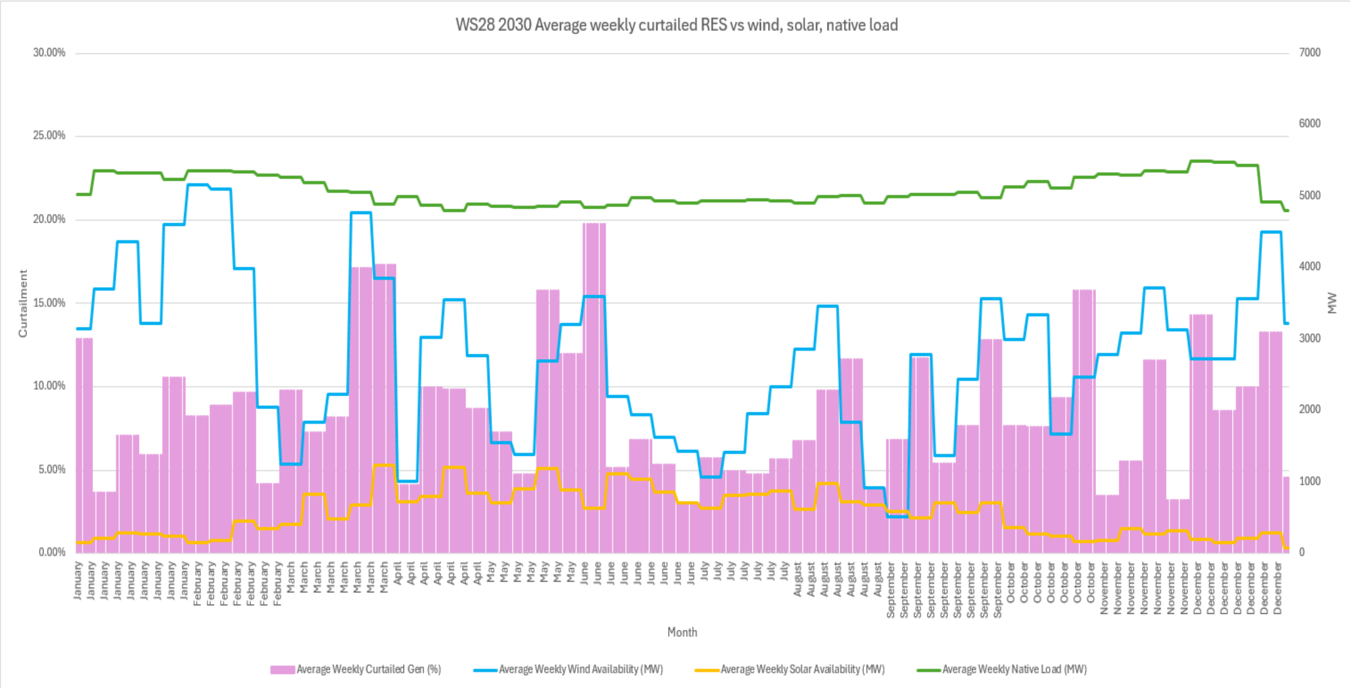
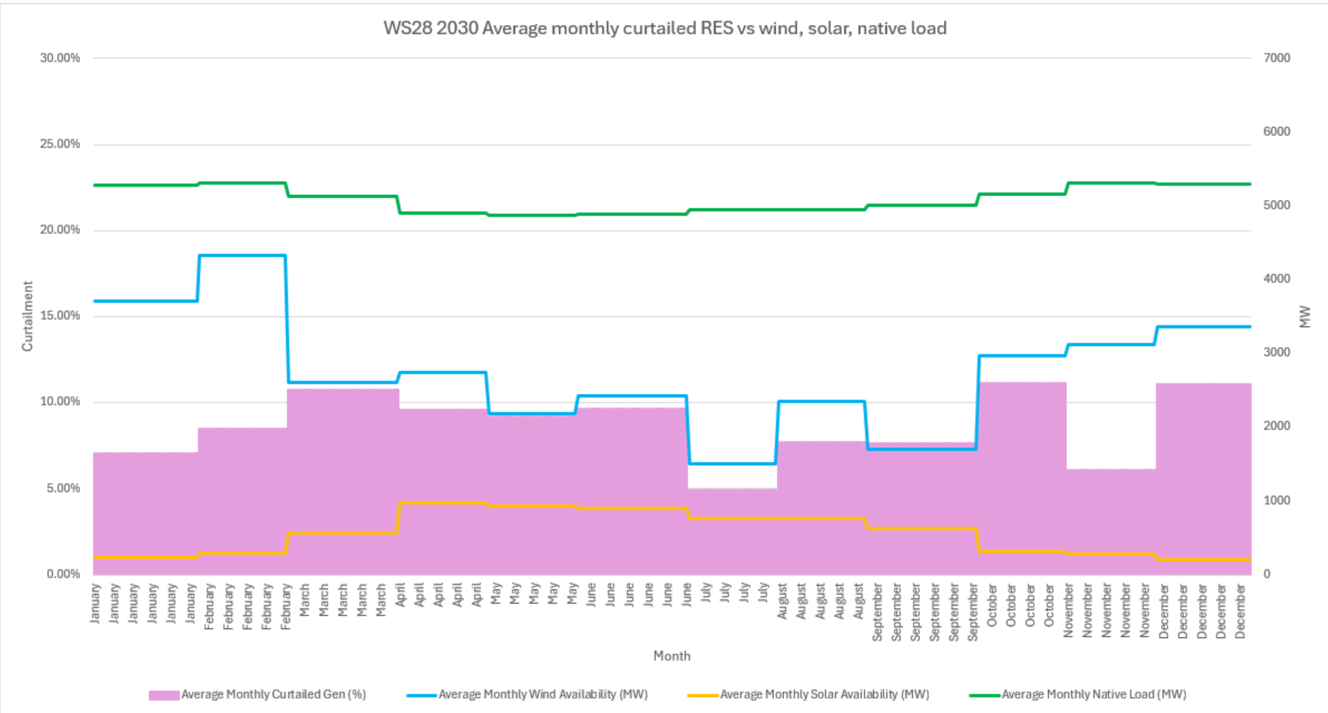


Figure 24: Average monthly RES generation curtailment vs wind, solar, native load, 2030, WS28 – Article 8(4)(d)



From these graphs there does not appear to be a clear correlation between RES generation curtailment and wind power, solar power, or load. The graphs do show there an increasing likelihood of curtailment of a type of VRES (e.g. wind, solar) as the level of penetration of that type of VRES increases, therefore a larger penetration would result in a larger correlation. For example, if more of one VRES type is built than another, the correlation between that VRES type and RES generation curtailment would increase.

The following graphs and tables provide results on the distribution of the correlation coefficient between RES generation curtailment and three drivers for RES generation curtailment (wind availability, solar availability and native load), considering the number of days where the correlation coefficient is within a certain range. The correlation coefficient is calculated on a daily basis, i.e. each coefficient number is the correlation between hourly RES generation curtailment timeseries of wind availability and curtailed generation on the day. In general, the more days where the correlation coefficient is in a higher range of values, the more positively correlated RES generation curtailment is with the driver considered, and the more days where the correlation coefficient is in a lower range of negative values, the more negatively correlated RES generation curtailment is with the driver considered.

WS28 2028

Figure 25: Correlation Distribution Wind vs Curtailed Generation, 2028, WS28 – Article 8(4)(d)

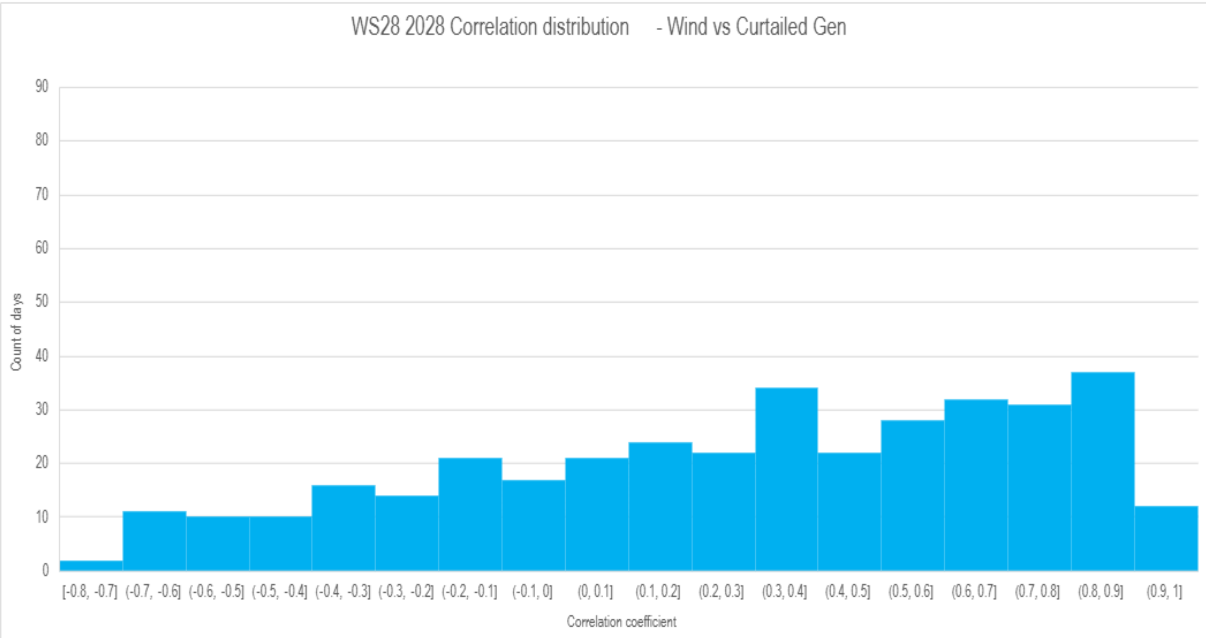


Figure 26: Correlation Distribution Solar vs Curtailed Generation, 2028, WS28 – Article 8(4)(d)

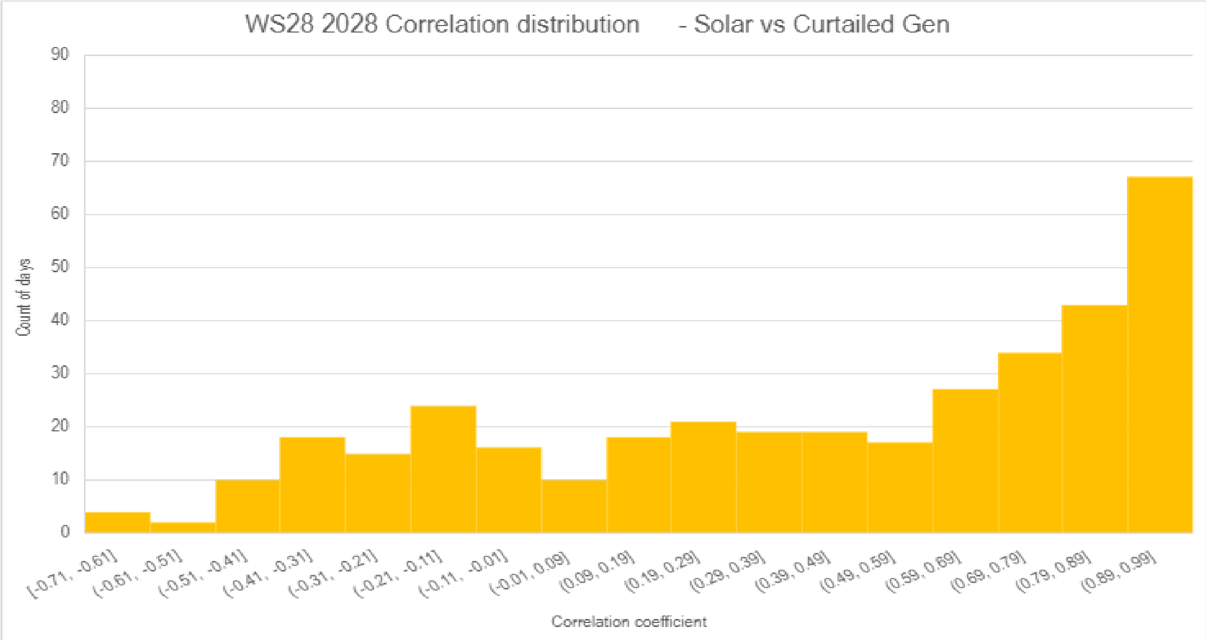
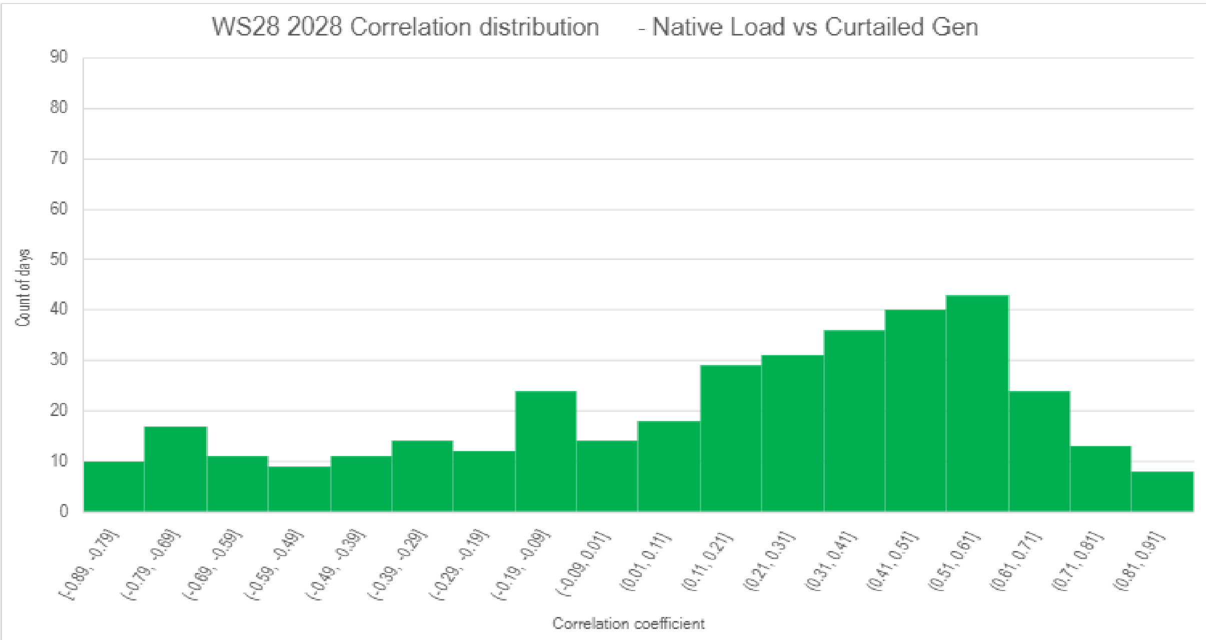


Figure 27: Correlation Distribution Native Load vs Curtailed Generation (as per the ACER Methodology requirement), 2028, WS28 – Article 8(4)(d)



WS28 2030

Figure 28: Correlation Distribution Wind vs Curtailed Generation, 2030, WS28 – Article 8(4)(d)

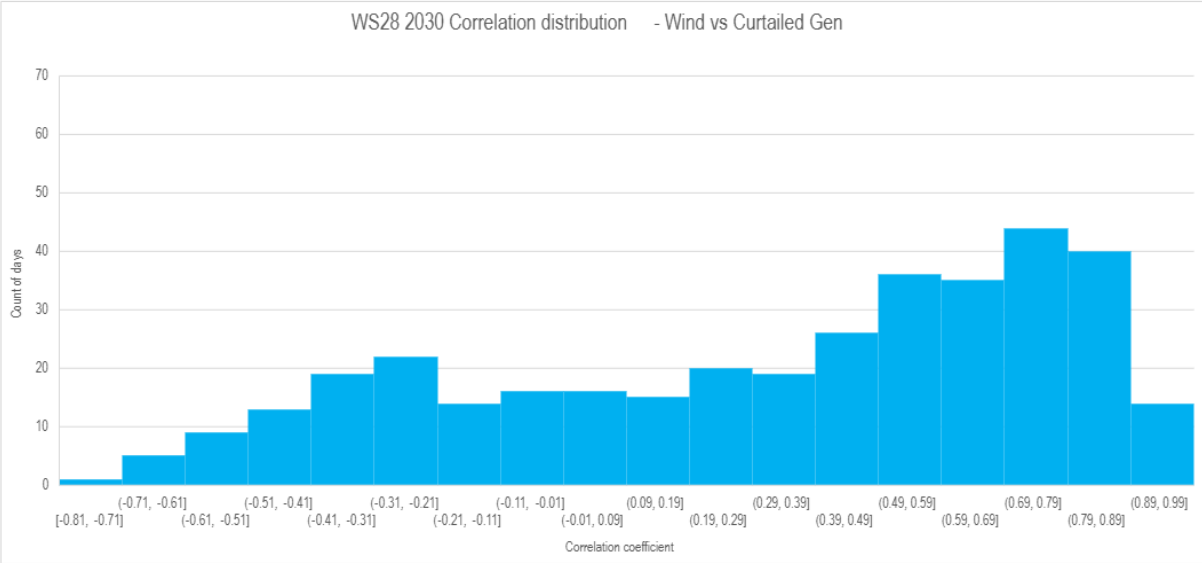


Figure 29: Correlation Distribution Solar vs Curtailed Generation, 2030, WS28 – Article 8(4)(d)

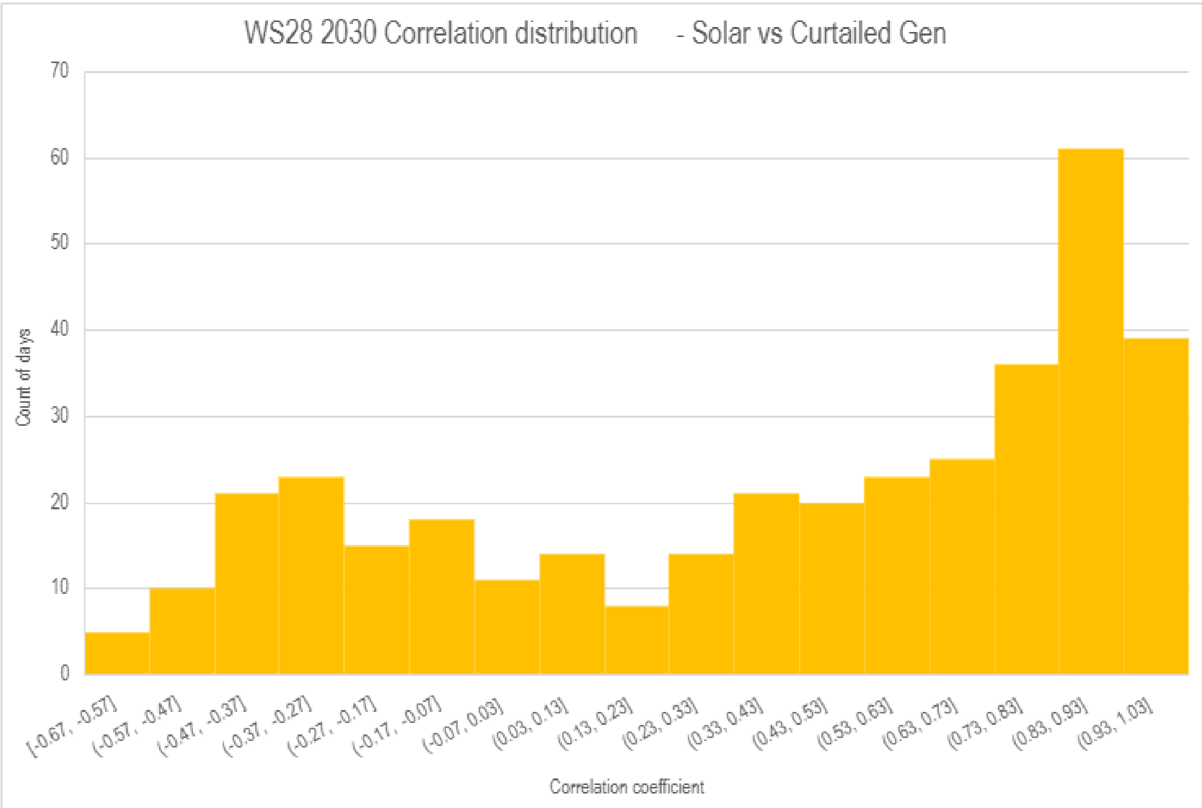
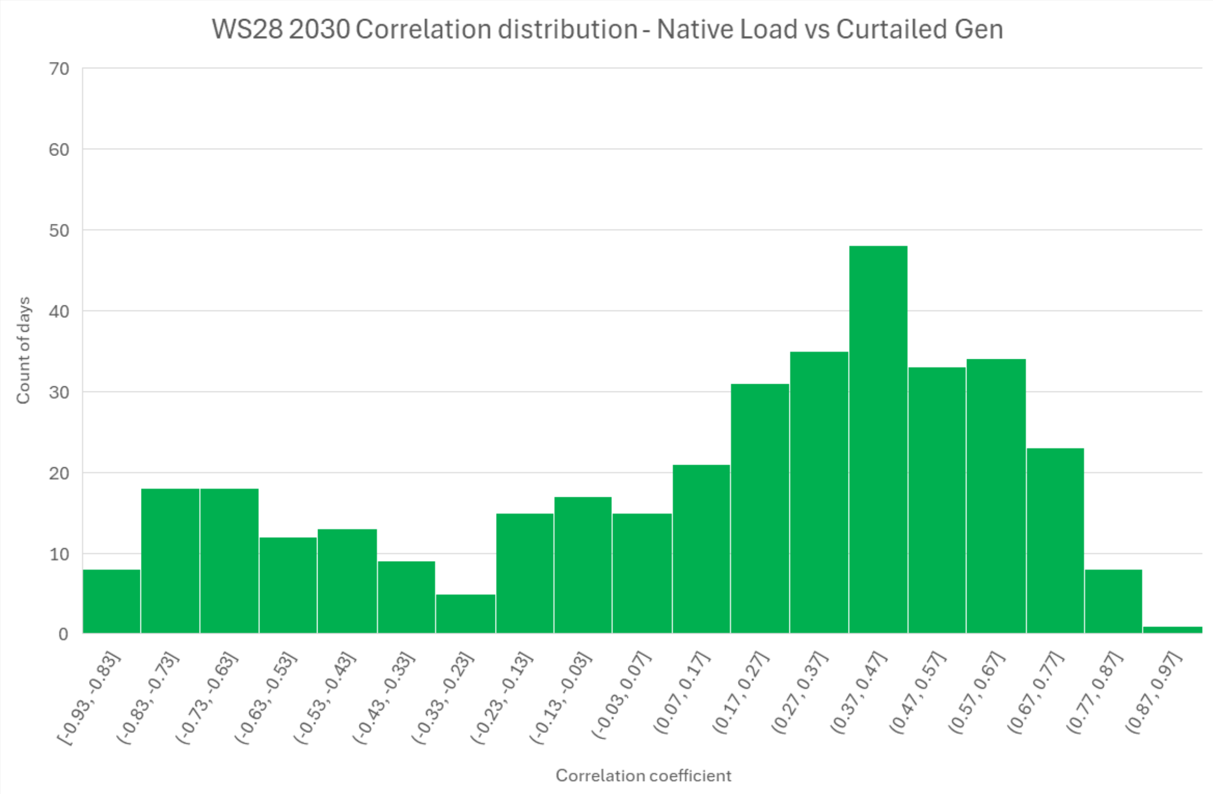


Figure 30: Correlation Distribution Native Load vs Curtailed Generation, 2030, WS28 – Article 8(4)(d)



The results show that there are days where there is a larger positive correlation between solar power and RES generation curtailment. This suggests that when there is a day with a high level of RES generation curtailment, it tends to coincide with there being a high level of solar availability. However, in general, the results show that there is no very clear correlation for all three energy drivers for most of the year i.e. while each driver may have greater levels of either positive or negative correlation, there are consistent levels of both positive and negative correlation in all cases. This is due to there being so many periods where no RES generation curtailment arises, which are included in the analysis.

The following graphs are a repeat of this analysis but where the data for hours with zero RES generation curtailment are excluded. This provides an additional view where it is possible to see the correlation of RES generation curtailment with demand, wind, and solar when there is RES generation curtailment occurring, removing any skewing in the previous correlations caused by correlating demand, wind, and solar with periods of zero RES generation curtailment.

WS28 2028

Figure 31: Correlation Distribution (Positive Curtailment) Wind vs Curtailed Generation, 2028, WS28 – Article 8(4)(d)

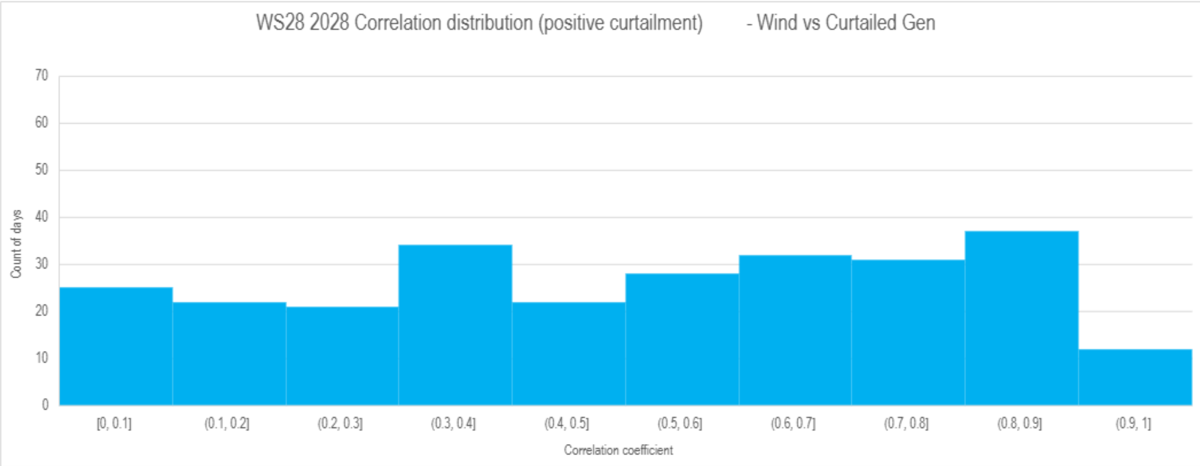


Figure 32: Correlation Distribution (Positive Curtailment) Solar vs Curtailed Generation, 2028, WS28 – Article 8(4)(d)

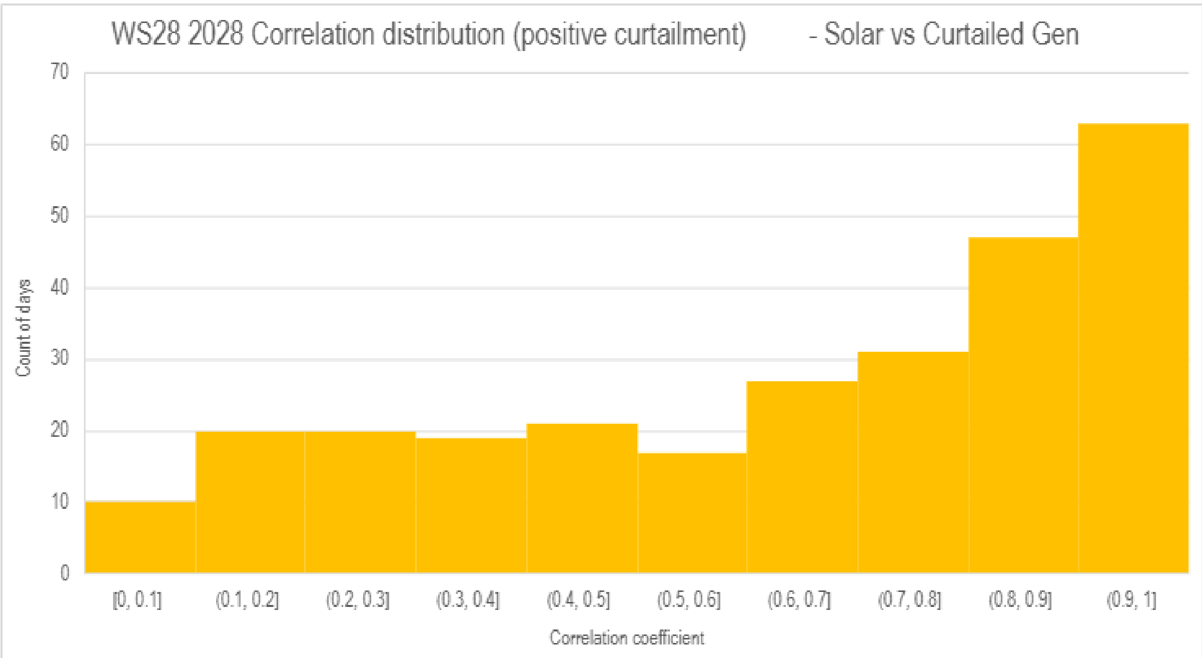
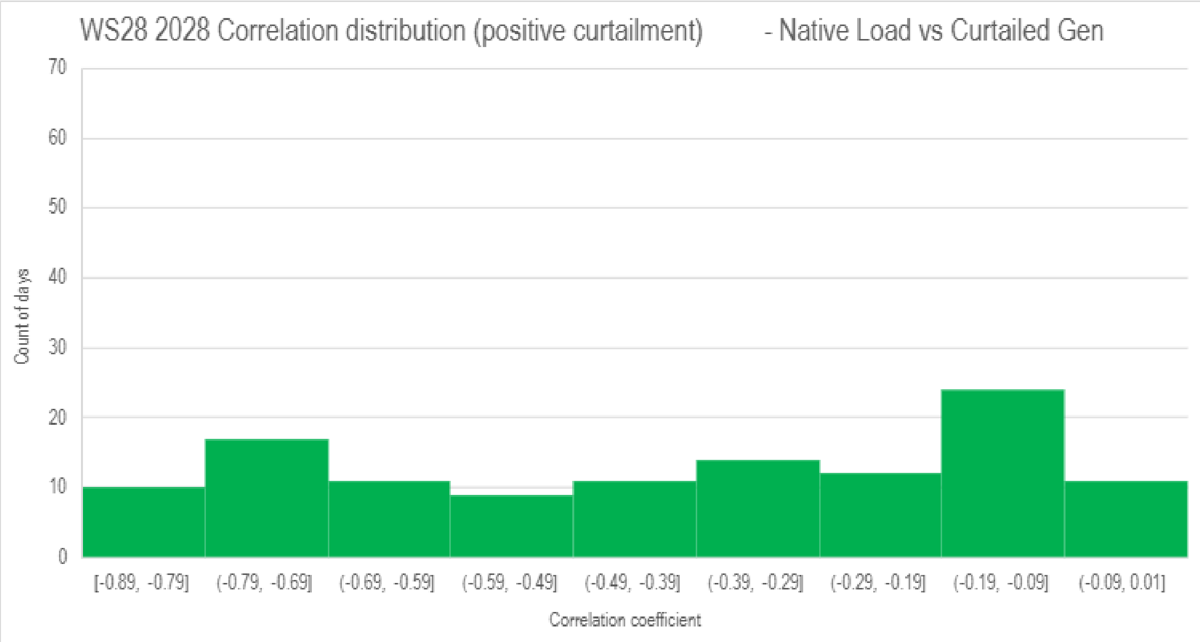


Figure 33: Correlation Distribution (Positive Curtailment) Native Load vs Curtailed Generation, 2028, WS28 – Article 8(4)(d)



WS28 2030

Figure 34: Correlation Distribution (Positive Curtailment) Wind vs Curtailed Generation, 2030, WS28 – Article 8(4)(d)

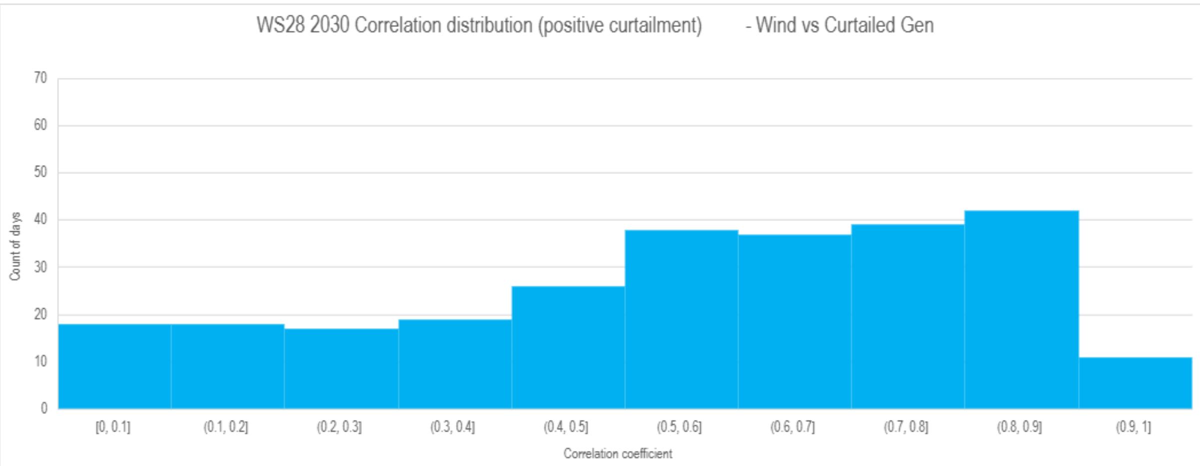


Figure 35: Correlation Distribution (Positive Curtailment) Solar vs Curtailed Generation, 2030, WS28 – Article 8(4)(d)

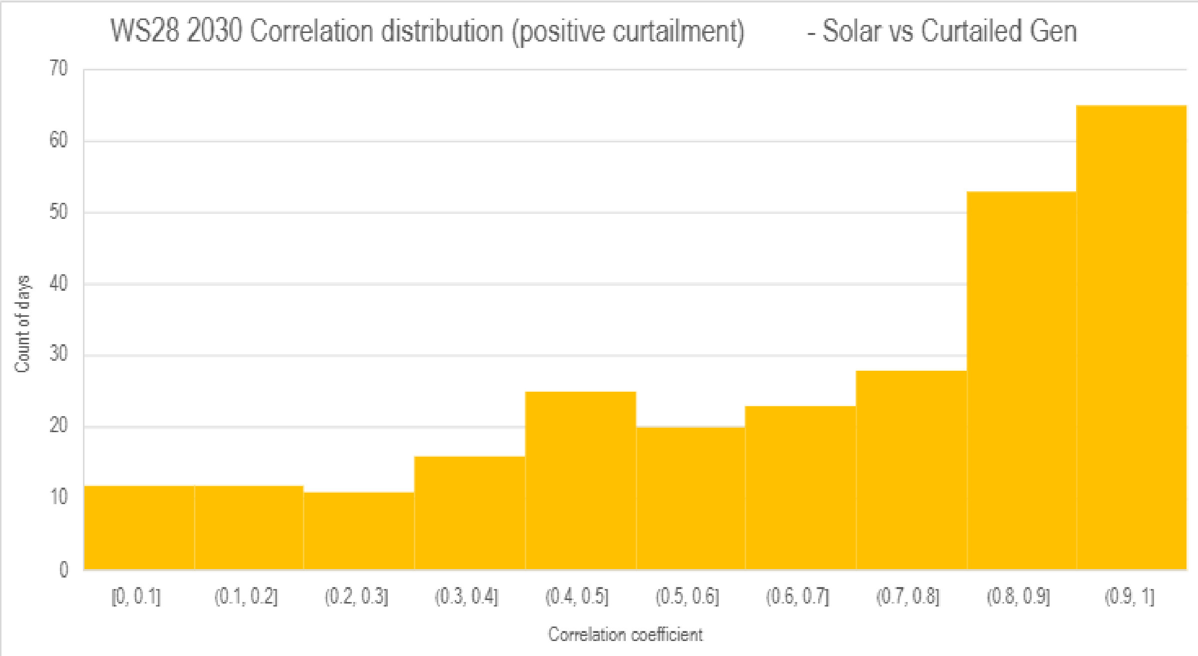
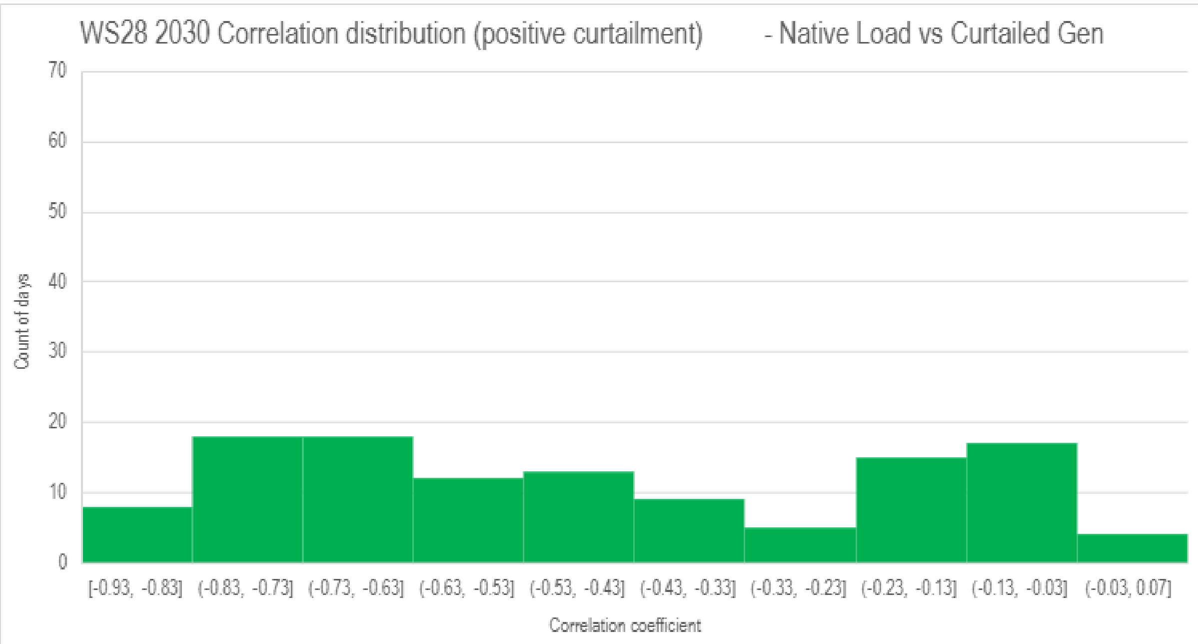


Figure 36: Correlation Distribution (Positive Curtailment) Native Load vs Curtailed Generation, 2030, WS28 – Article 8(4)(d)



When periods with no RES generation curtailment are removed from the analysis, the correlation against RES generation becomes more apparent. Wind availability is strongly positively correlated with RES generation curtailment, with the correlation coefficient exceeding 0.5 for a large proportion of the year. For the same level of coefficient, solar has a greater number of days which also indicates solar availability is correlated with RES generation curtailment. It should be noted that generally load has a negative correlation with

RES generation curtailment (i.e. more load means less RES generation curtailment), with a slight increase in the number of days the correlation coefficient is below -0.5 for native load, but in general the distribution is more evenly spread with similar numbers of days across all negative correlation coefficient values, so the level of correlation is not as strong as it is for wind and solar.

The annual correlations between hourly time series of curtailment and wind, solar availability and native load are shown in the tables below.

Table 16: Annual correlations between hourly time series of curtailment and wind, solar availability and native load, WS28 – Article 8(4)(d)

	WS28 2028			WS28 2030		
	Annual average of daily correlation coefficient	Annual average of weekly correlation coefficient	Annual average of monthly correlation coefficient	Annual average of daily correlation coefficient	Annual average of weekly correlation coefficient	Annual average of monthly correlation coefficient
Wind vs Curtailed gen	0.50	0.49	0.52	0.57	0.54	0.60
Solar vs Curtailed gen	0.34	0.37	0.33	0.30	0.35	0.28
Native load vs Curtailed gen	-0.03	0.06	0.00	-0.09	0.00	-0.08

Table 17: Annual correlations between hourly time series of curtailment and wind, solar availability and native load, WS4 – Article 8(4)(d)

	WS4 2028			WS4 2030		
	Annual average of daily correlation coefficient	Annual average of weekly correlation coefficient	Annual average of monthly correlation coefficient	Annual average of daily correlation coefficient	Annual average of weekly correlation coefficient	Annual average of monthly correlation coefficient
Wind vs Curtailed generation	0.53	0.54	0.56	0.58	0.53	0.59
Solar vs Curtailed generation	0.39	0.35	0.31	0.33	0.33	0.28
Native load vs Curtailed generation	-0.01	0.09	0.04	-0.08	0.01	-0.05

Table 18: Annual correlations between hourly time series of curtailment and wind, solar availability and native load, WS34 – Article 8(4)(d)

	WS34 2028			WS34 2030		
	Annual average of daily correlation coefficient	Annual average of weekly correlation coefficient	Annual average of monthly correlation coefficient	Annual average of daily correlation coefficient	Annual average of weekly correlation coefficient	Annual average of monthly correlation coefficient
Wind vs Curtailed generation	0.51	0.52	0.55	0.61	0.56	0.61
Solar vs Curtailed generation	0.34	0.38	0.33	0.28	0.37	0.31
Native load vs Curtailed generation	0.04	0.10	0.05	-0.02	0.02	-0.02

The results show that there is a more positive correlation annually for wind power which means that adding more wind power capacity and availability would result in higher annual RES generation curtailment than adding more solar power capacity and availability. As VRES penetration increases for a particular technology, it is expected that correlations would increase for the monthly time period first, then weekly, then daily.

5.1.2 Residual load time series

The following tables outline the results for the residual load indicators, firstly the sum of the absolute variations between the actual residual load and the average over different timeframes (hourly, daily, monthly) and then representing the average of these variations rather than the total sum. These averages are useful to indicate how much residual load variation may be expected in the difference between the time periods (e.g. between hours, between days, between months), which could be an indicator of the MW level of flexible resources with different durations that could help meet the needs caused by those variations.

These results have been produced in line with Article 8(5).

Table 19: Residual load time series across all weather scenarios and target years | Hourly, Daily & Seasonal Indicators - Article 8(5)

	WS28		WS4		WS34	
Sum (GWh)	**2028**	**2030**	**2028**	**2030**	**2028**	**2030**
Hourly Indicator	6212	7143	6579	7827	6111	7163
Daily Indicator	6702	7950	5837	7418	6827	8064
Monthly Indicator	2365	2892	3473	4307	2453	3457

Table 20: Residual load variation as an average across all weather scenarios | Hourly, Daily & Seasonal Indicators - Article 8(5)

	WS28		WS4		WS34	
Avg. (GWh)	**2028**	**2030**	**2028**	**2030**	**2028**	**2030**
Hourly Ave of hourly indicator	0.7	0.8	0.8	0.9	0.7	0.8
Daily Ave of daily indicator	18.4	21.8	16.0	20.3	18.7	22.1
Monthly Ave of daily indicator	197.1	241.0	289.4	358.9	204.4	288.1

These results show that, on average, RES generation curtailment in an hour is likely to vary from the average value over the last 24 hours by between 0.7 GWh and 0.9GWh depending on the year and scenario. To cover these average variations, between 175MW and 225MW of 4-hour duration flexibility would be able to cover the average difference between each hour of residual load and the hourly average over the previous day. This can then be compared against the total value over the year to indicate the level of use of that flexibility. Similar estimates could be gained by considering different combinations of durations of flexibility that would be suitable to cover the average daily or monthly variations. However, these indicators may not be as useful for drawing insights on the potential levels of flexibility required to help meet RES integration flexibility needs as others provided throughout this analysis.

5.1.3 RES integration target

Article 8(7) outlines requirements to extract and process or interpret values from the National Energy and Climate Plan[38] to help determine the level of RES integration targets. For this analysis these figures have been taken from Table 9 at the link provided, where the RES-E target for 2028 is 60% and the RES-E target for 2030 is 80%.

Table 21 below provides a summary of the penetration level of VRES that would be possible with the full VRES availability as input to the FNA model, assuming no dispatch down. This is provided for VRES on its own as a percentage of total generation, and then for all RES as a percentage of Total Energy Requirement for comparison against the NECP target. The second of these metrics is included as it is the relevant metric for considering the extent to which the RES integration targets can be met, considering all RES, not just Variable RES but also for example hydroelectric power generation, and comparing them with the Total Energy Requirement. The first metric focussing on just the VRES element and considering it as a percentage of total generation rather than Total Energy Requirement is also included to provide a more intuitive sense of the level of generation from the main drivers for flexibility needs considered in this analysis, being Variable RES sources such as Wind and Solar.

[38] NECP

Table 21: IE Base Available VRES, % of Total Generation vs. NECP WAM Targets across all weather scenarios and target year - Article 8(6), 8(7), 8(8), 8(9)

FNA Scenario	IE Base Available VRES, % of Total Generation (potential penetration of VRES by energy, assuming no dispatch down).	IE Base Available RES, % of Total Energy Requirement RES generation / (Total Generation + Import – Export) (potential penetration of all RES by energy, assuming no dispatch down).	NECP WAM Target
2028 WS 34	53.35	50.66	60
2028 WS 28	51.47	49.92	60
2028 WS 4	51.81	50.70	60
2030 WS 34	64.12	65.35	80
2030 WS 28	62.64	64.53	80
2030 WS 4	63.30	65.69	80

This shows that the available RES generation amounts to a penetration level which is below the NECP target, even with 0% RES generation curtailment. Therefore, for the purposes of this FNA report, Article 8(9) is not applicable as there are no uncovered RES integration flexibility needs according to the calculation approach required in the methodology, i.e. there is no level of allowed RES generation curtailment which would allow the level of RES generation to equal the NECP target with the inputs to the model required under the FNA methodology.

As a result, the analysis required under Articles 8(10), (1), (12), and (14) is not applicable for this iteration of the FNA. More information on this can be found in Appendix A.

5.1.4 RES dispatch down values due to system and transmission network

Table 22 summarise the values for RES dispatch down due to system reasons and RES dispatch down due to transmission network reasons from the modelling results used for each scenario and year. These results have been produced in line with Article 8(13).

Table 22: RES dispatch down values due to system and transmission network reasons across all weather scenarios and target years - Article 8(13)

	WS28		WS4		WS34	
	2028	2030	2028	2030	2028	2030
RES dispatch down due to surplus + curtailment (MWh)	383,701	2,101,992	495,242	2,139,436	398,298	2,234,141
RES dispatch down due to constraint (MWh)	2,813,528	1,720,343	2,813,528	1,720,343	2,813,528	1,720,343
% of total dispatch down due to constraint	88.00%	45.01%	85.03%	44.57%	87.60%	43.50%

These results show that the proportion of overall RES dispatch down due to transmission network reasons is always above the 10% threshold outlined in Article 14(3) of the ACER Methodology, making it relevant to include those results in fine-tuning of the RES integration needs.

5.1.5 Sub-indicators

The ACER methodology refers to sub-indicators as the technical requirements of the flexibility needs and sets out that these indicators can assist in the identification of the most suitable resources to cover them.

While, as outlined in Section 5.1.3 there is technically no uncovered RES integration flexibility needs as it is defined under the FNA Methodology, it was determined that providing the results for these sub indicators across all periods with RES dispatch down would provide useful context and understanding for characterising the RES integration needs and therefore the potential avenues to help meet those needs. The following results are provided to give a number of characterisations of the relevant sub-indicators required for Article 16(5):

a) number of MTUs showing an uncovered need;

b) interval between uncovered needs;

c) duration of uncovered needs;

d) volume of uncovered needs in terms of energy and power

These are split by hourly, daily, and monthly considerations, and also split by the results for system flexibility needs from the FNA model and transmission network flexibility needs from the ECP model. Graphs are provided to give a visual indication of the results, while the tables provide more specific quantitative details of the results, showing how consistently the needs arise, the relevant continuous durations of the needs, and durations between the needs, over different timescales. The results are also split by the system flexibility needs, and the transmission network flexibility needs to give a clearer indication of the main drivers – the results are presented here together for better clarity and insight rather than separating the transmission network flexibility needs analysis into a separate section.

Hourly Sub-Indicators

Figure 37: Hourly dispatch down for system vs transmission curtailment (MW), 2028, WS28 – Article 16(5)

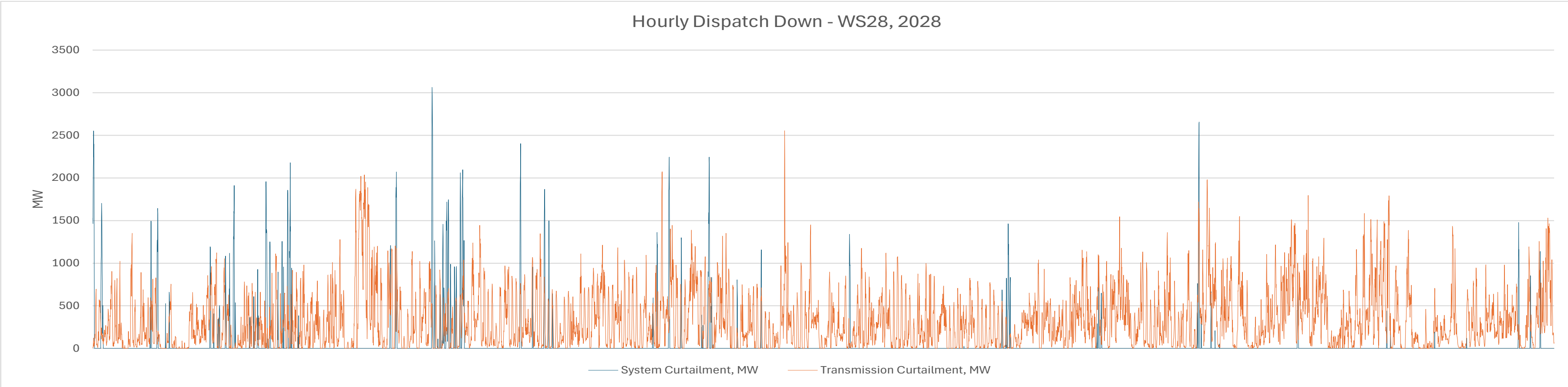


Figure 38: Hourly dispatch down for system vs transmission curtailment (MW), 2030, WS28 – Article 16(5)

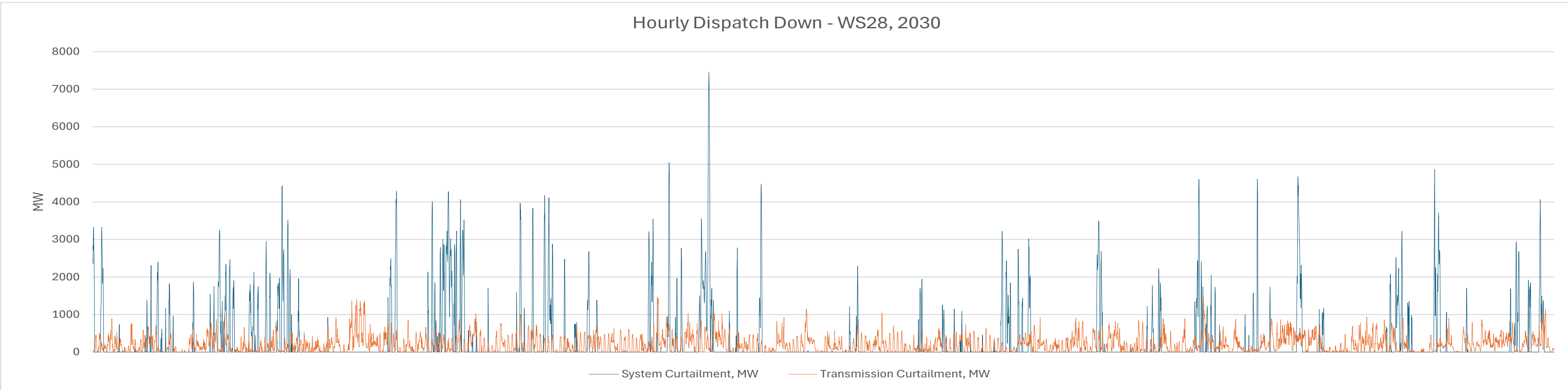


Table 23: Hourly system curtailment needs across all weather scenarios and target years – Article 16(5)

	WS28		WS4		WS34	
	2028	2030	2028	2030	2028	2030
Total number of hours showing a need (hr)	457	1,443	543	1,393	471	1,495
Total volume of need (MWh)	383,701	2,101,992	495,242	2,139,436	398,298	2,234,141
Average hourly volume of need (MW)	44	241	57	245	46	256
Average non-zero hourly volume of need (MW)	840	1,457	912	1,536	846	1,494
Minimum non-zero hourly need (MW)	2.85	0.31	5.19	1.10	0.81	0.62
Maximum hourly need (MW)	3,063	7,455	3,363	6,498	5,211	6,516
Number of blocks of need	82	160	88	156	92	162
Average duration of need (hr)	5.57	9.02	6.17	8.93	5.12	9.17
Min non-zero duration of need (hr)	1	1	1	1	1	1
Max duration of need (hr)	18	70	27	46	21	83
Standard Deviation of duration of need (hr)	3.46	8.95	4.24	7.48	3.94	10.09
Average interval between needs (hr)	100.96	45.58	92.06	46.77	88.87	44.42
Min non-zero interval between needs (hr)	1	1	1	1	1	1
Max interval between needs (hr)	679	392	1021	585	896	569
Standard Deviation of interval between needs (hr)	166.53	73.87	181.63	85.94	161.45	74.87

Table 24: Hourly transmission curtailment needs across all weather scenarios and target years – Article 16(5)

	WS28		WS4		WS34	
	2028	2030	2028	2030	2028	2030
Total number of hours showing a need (hr)	8,217	7,865	8,217	7,865	8,217	7,865
Total volume of need (MWh)	2,803,486	1,711,642	2,803,486	1,711,642	2,803,486	1,711,642
Average hourly volume of need (MW)	321	196	321	196	321	196
Average non-zero hourly volume of need (MW)	341	218	341	218	341	218
Minimum non-zero hourly need (MW)	0.01	0.01	0.01	0.01	0.01	0.01
Maximum hourly need (MW)	2,554	1,471	2,554	1,471	2,554	1,471
Number of blocks of need	118	229	118	229	118	229
Average duration of need (hr)	69.04	34.20	69.04	34.20	69.04	34.20
Min non-zero duration of need (hr)	1	1	1	1	1	1
Max duration of need (hr)	744	723	744	723	744	723
Standard Deviation of duration of need (hr)	127.35	71.44	127.35	71.44	127.35	71.44
Average interval between needs (hr)	4.37	3.79	4.37	3.79	4.37	3.79
Min non-zero interval between needs (hr)	1	1	1	1	1	1
Max interval between needs (hr)	34	32	34	32	34	32
Standard Deviation of interval between needs (hr)	4.82	3.79	4.82	3.79	4.82	3.79

Daily Sub-Indicators

Figure 39: Daily dispatch down for system vs transmission curtailment (MWh), 2028, WS28 – Article 16(5)

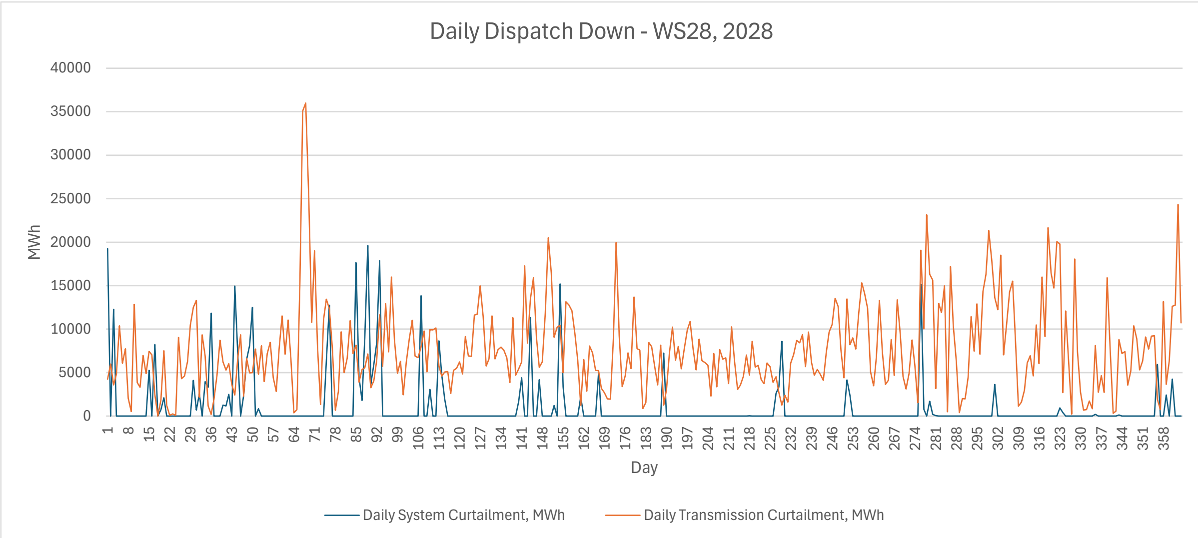


Figure 40: Daily dispatch down for system vs transmission curtailment (MWh), 2030, WS28 – Article 16(5)

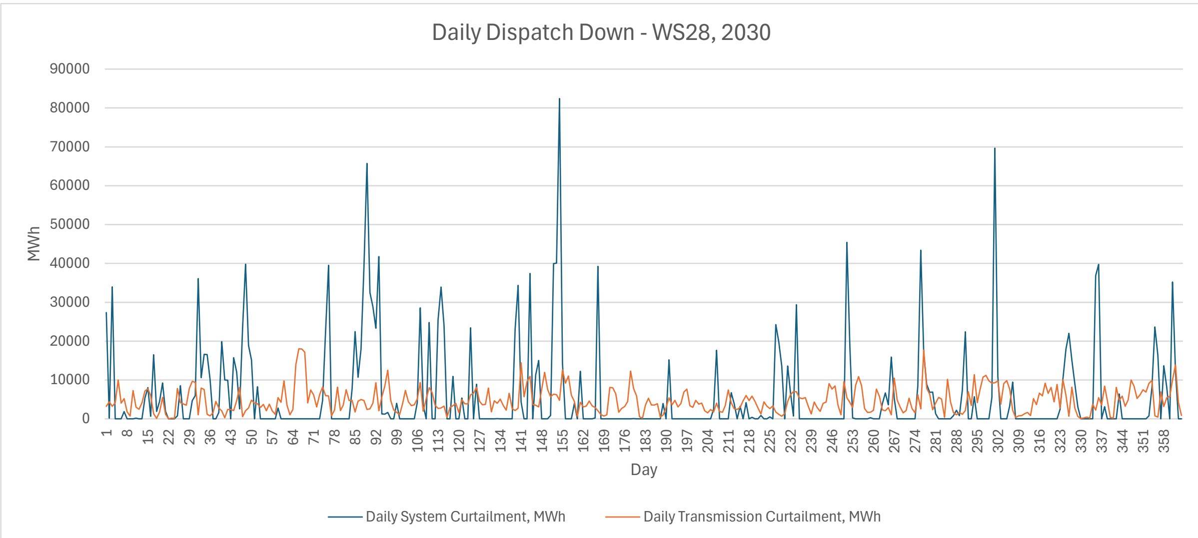


Table 25: Daily system curtailment needs across all weather scenarios and target years – Article 16(5)

	WS28		WS4		WS34	
	2028	2030	2028	2030	2028	2030
Number of days showing a need:	67	144	68	140	68	146
Average daily volume of need (MWh)	1,054	5,775	1,361	5,878	1,094	6,138
Average non-zero daily volume of need (MWh)	5,727	14,597	7,283	15,282	5,857	15,302
Minimum non-zero daily need (MWh)	24.71	50.59	56.30	10.30	4.39	0.62
Maximum daily need (MWh)	19,606	82,411	24,007	68,988	30,023	75,002
Number of blocks of days with need	36	55	41	56	36	47
Average duration of days with need (days)	1.86	2.62	1.66	2.50	1.89	3.11
Min non-zero duration of days with need (days)	1	1	1	1	1	1
Max duration of days with need (days)	9	13	4	12	6	11
Standard Deviation of duration of days with need (days)	1.47	2.37	0.98	2.56	1.37	2.47
Average interval between days with needs (days)	8	4	7	4	8	5
Min non-zero interval between days with needs (days)	1	1	1	1	1	1
Max interval between days with needs (days)	28	16	42	24	37	23
Standard Deviation of interval between days with needs (days)	8.35	3.79	9.62	4.75	8.48	3.96

Table 26: Daily transmission curtailment needs across all weather scenarios and target years – Article 16(5)

	WS28		WS4		WS34	
	2028	2030	2028	2030	2028	2030
Number of days showing a need:	363	364	363	364	363	364
Average daily volume of need (MWh)	7,702	4,702	7,702	4,702	7,702	4,702
Average non-zero daily volume of need (MWh)	7,723	4,702	7,723	4,702	7,723	4,702
Minimum non-zero daily need (MWh)	73.54	27.01	73.54	27.01	73.54	27.01
Maximum daily need (MWh)	36,002	18,033	36,002	18,033	36,002	18,033
Number of blocks of days with need	2	1	2	1	2	1
Average duration of days with need (days)	181.50	364.00	181.50	364.00	181.50	364.00
Min non-zero duration of days with need (days)	17	364	17	364	17	364
Max duration of days with need (days)	346	364	346	364	346	364
Standard Deviation of duration of days with need (days)	164.50	0.00	164.50	0.00	164.50	0.00
Average interval between days with needs (days)	1	0	1	0	1	0

Min non-zero interval between days with needs (days)	1	0	1	0	1	0
Max interval between days with needs (days)	1	0	1	0	1	0
Standard Deviation of interval between days with needs (days)	0.00	0.00	0.00	0.00	0.00	0.00

Monthly Sub-Indicators

Figure 41: Monthly dispatch down for system vs transmission curtailment (MWh), 2028, WS28 – Article 16(5)

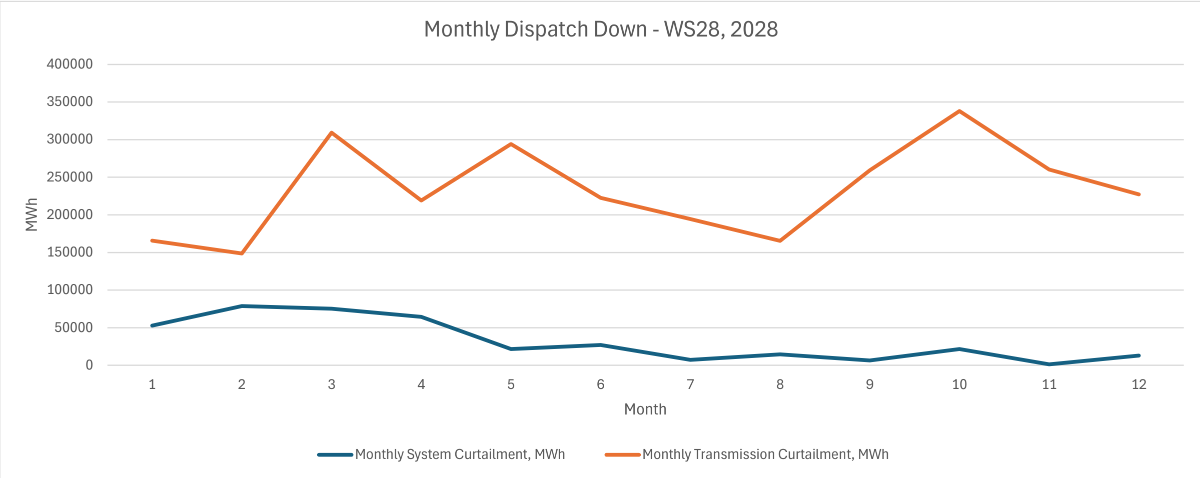


Figure 42: Monthly dispatch down for system vs transmission curtailment (MWh), 2030, WS28 – Article 16(5)

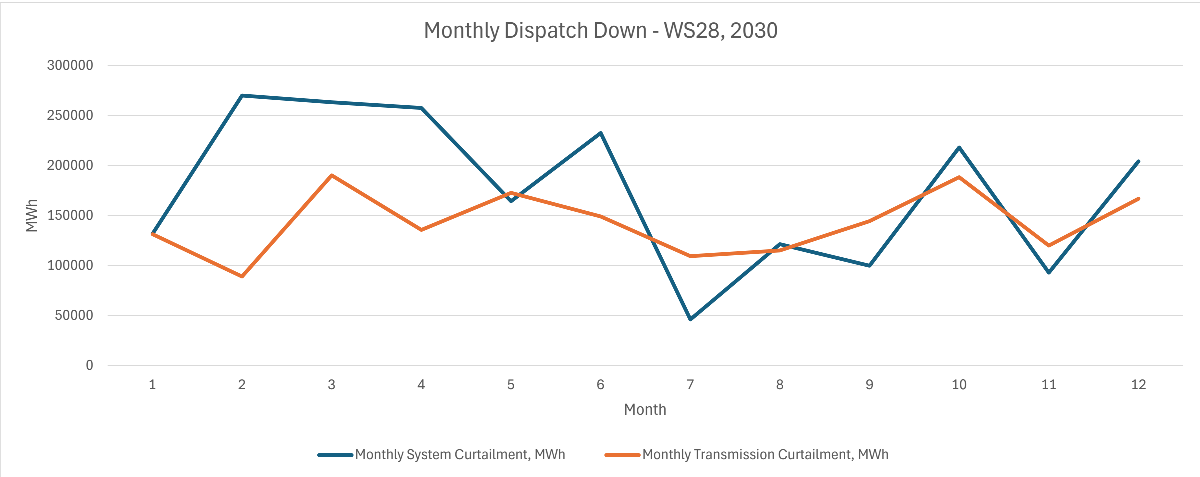


Table 27: Monthly system curtailment needs across all weather scenarios and target years – Article 16(5)

	WS28		WS4		WS34	
	2028	2030	2028	2030	2028	2030
Number of months showing a need	12	12	11	12	12	12
Average monthly volume of need (MWh)	31,975	175,166	41,270	178,286	33,191	186,178
Minimum monthly need (MWh)	1,345	46,075	0	16,163	9,384	94,759
Maximum monthly need (MWh)	78,852	270,046	138,554	538,957	94,011	375,514
Number of blocks of months with need	1	1	2	1	1	1
Average duration of months with need (months)	12	12	5.5	12	12	12
Min non-zero duration of months with need (months)	12	12	1	12	12	12
Max duration of months with need (months)	12	12	10	12	12	12
Standard Deviation of duration of months with need (months)	0	0	4.5	0	0	0
Average interval between months with needs (months)	0	0	1	0	0	0
Min non-zero interval between months with needs (months)	0	0	1	0	0	0
Max interval between months with needs (months)	0	0	1	0	0	0
Standard Deviation of interval between months with needs (months)	0	0	0	0	0	0

Table 28: Monthly transmission curtailment needs across all weather scenarios and target years – Article 16(5)

	WS28		WS4		WS34	
	2028	2030	2028	2030	2028	2030
Number of months showing a need	12	12	12	12	12	12
Average monthly volume of need (MWh)	233,624	142,637	233,624	142,637	233,624	142,637
Minimum monthly need (MWh)	148,750	88,974	148,750	88,974	148,750	88,974
Maximum monthly need (MWh)	337,914	190,223	337,914	190,223	337,914	190,223
Number of blocks of months with need	1	1	1	1	1	1
Average duration of months with need (months)	12	12	12	12	12	12
Min non-zero duration of months with need (months)	12	12	12	12	12	12
Max duration of months with need (months)	12	12	12	12	12	12
Standard Deviation of duration of months with need (months)	0	0	0	0	0	0
Average interval between months with needs (months)	0	0	0	0	0	0
Min non-zero interval between months with needs (months)	0	0	0	0	0	0
Max interval between months with needs (months)	0	0	0	0	0	0
Standard Deviation of interval between months with needs (months)	0	0	0	0	0	0

These results show that while the volumes of RES dispatch down are greater over the winter months, there are relatively consistent RES dispatch down volumes throughout the year. In 2028 this is primarily due to transmission network constraints, but in 2030 there is a consistent level of dispatch down due to system flexibility reasons (i.e. surplus and curtailment). While there are individual or shorter duration periods with higher levels of RES dispatch down, the main outcome appears to be lower but still relatively high average levels of RES dispatch down across all the different durations (daily, weekly, monthly, the durations of the continuous RES dispatch down periods). This indicates that the RES integration flexibility need is not necessarily just for large MW to cover short periods or large MWh to cover longer periods, but a combination of both. RES dispatch down tends to show quite "blocky" characteristics, as when it arises it tends to be for relatively long durations with relatively high level of dispatch down in MW terms. These "blocky" features of the duration of RES dispatch down events appear to increase between 2028 and 2030, which appears to be related to the increase in RES capacity and availability. This also suggests a need for additional capacity of flexibility sources as well as longer duration or larger MWh consumption capabilities from these flexibility sources to help meet the RES integration flexibility needs across the durations of the RES dispatch down events.

5.1.6 Additional data and analysis

Additional results are provided below to present annual renewable dispatch-down outcomes split between surplus, curtailment and constraint drivers. These results are provided under Article 1(6), which allows for additional data and analysis, and Article 16(11), which provides for the assessment of alternative solutions, including additional RES capacity. The results focus on metrics and scenarios that EirGrid considers more representative and useful. In particular, values are provided which are focussed on total annual dispatch down, and a High RES scenario which considers an increased level of RES capacity sufficient to meet NECP targets, please see Section 2.4 and 2.5 for more details. While these results consider constraint dispatch down, the full transmission-level analysis is set out in Section 6.

Table 29: Annual dispatch down results for Base and High RES scenarios for 2028 and 2030 across all weather scenarios split by surplus, curtailment, and constraint drivers – Article 1(6), 16(11)

	Base scenario			High RES Scenario		
FNA scenario	IE annual surplus + curtailment dispatch down (%)	IE annual constraint dispatch down (%)	**IE annual total dispatch down (%)**	IE annual surplus + curtailment dispatch down (%)	IE annual constraint dispatch down (%)	**IE annual total dispatch down (%)**
2028 WS4	2.33%	9.84%	**12.17%**	7.01%	10.82%	**17.83%**
2028 WS28	1.84%	9.84%	**11.68%**	6.36%	10.82%	**17.18%**
2028 WS34	1.89%	9.84%	**11.73%**	6.74%	10.82%	**17.56%**
2030 WS4	7.27%	6.05%	**13.32%**	22.47%	7.10%	**29.54%**
2030 WS28	7.26%	6.05%	**13.32%**	23.00%	7.10%	**30.10%**
2030 WS34	7.65%	6.05%	**13.7%**	23.62%	7.10%	**30.72%**

For clarity, the results for the surplus + curtailment values were taken from the FNA model developed as outlined under Section 2, while the constraint dispatch down values were taken from the relevant ECP model as outlined in Section 3. However, it is important to distinguish between the two primary drivers considered in this FNA model in SEM context in terms of understanding the main drivers and potential levers for reducing dispatch down. These two primary drivers are:

- Surplus – where RES availability is in excess of the available demand and interconnector flow position requiring the dispatch down of renewables to keep the system balanced from an energy perspective, and
- Curtailment – where system-wide operational requirements result in a need to dispatch down renewables for power system stability reasons

Modelling to determine the split between surplus and curtailment is carried out in the ECP modelling results, and the most recent ECP results are a useful reference, where from Figure 1 in the following link: (https://cms.eirgrid.ie/sites/default/files/publications/Constraints-Forecast-Studies-for-ECP-2.5-Ireland_summary.pdf) it can be seen that the proportion of surplus + curtailment dispatch down which is due to renewable surplus ranged between close to a half at a minimum to close to three quarters at a maximum in 2028, and from a half at a minimum to over four fifths in 2030, when considering the different main scenarios in that analysis. From that figure it can also be seen that in general when the level of RES installed capacity increases between different scenarios it tends to have a much larger impact on surplus than curtailment with a correlated increase in surplus.

A similar approach to that used in the ECP modelling was applied in the FNA modelling to distinguish between surplus and curtailment, ensuring consistency in the results. A version of the model was run where the drivers of curtailment actions are removed so that dispatch down would only arise due to surplus. This was done for the Base and High RES scenarios focussing on Weather Scenario 28, which when added alongside the other drivers for dispatch down. These results are set out in table 30.

Table 30: Annual dispatch down results for Base and High RES scenarios for 2028 and 2030 WS28 split by surplus, curtailment, and constraint drivers – Article 1(6), 16(11)

	Base scenario				High RES Scenario			
FNA scenario	IE annual surplus dispatch down (%)	IE annual curtailment dispatch down (%)	IE annual constraint dispatch down (%)	**IE annual total dispatch down (%)**	IE annual surplus dispatch down (%)	IE annual curtailment dispatch down (%)	IE annual constraint dispatch down (%)	**IE annual total dispatch down (%)**
2028 WS28	0.59%	1.25%	9.84%	**11.68%**	3.51%	2.85%	10.82%	**17.18%**
2030 WS28	4.37%	2.89%	6.05%	**13.32%**	18.54%	4.46%	7.10%	**30.10%**

These results for the High RES scenario are consistent with what is seen from the ECP modelling results, both in terms of the overall level of RES dispatch down and the relative splits between the surplus, curtailment, and constraint drivers. Constraint is a large driver for dispatch down (in particular in earlier years), but as installed RES capacity increases in future years or in higher RES capacity scenarios, the resulting increase in surplus is the biggest driver for increased RES dispatch down to the point that it can become the primary driver for RES dispatch down in the High RES 2030 scenario.

5.2 Ramping flexibility needs

For the purposes of this analysis, uncovered ramping needs can be defined as a total non-VRES generator ramping limitation which then results in VRES dispatch down.

As outlined in Section 2.2, based on the modelling approach followed by the TSO this task is limited to Article 9(11), and therefore the tasks in Articles 9(1) to 9(10) have not been carried out. For completeness, the results have been analysed for Ramping flexibility needs up and down from the FNA model, based on the following:

- For ramping up, the principle would be that if there is a zero ramp flexibility up value at the same time there is ENS, the ENS could have been caused by a lack of ramping flexibility
- For ramping down, the principle would be that if ramp flexibility down is zero for an hour where there is also RES curtailment, the RES curtailment could be because of uncovered ramping needs.

Following this analysis for all weather scenarios and target years for the base case scenario, this did not occur for ramping down as the ramp flexibility down did not equal zero. There is only one hundredth of a percentage of load as ENS in one scenario for ramp flexibility up (in WS28 2028). This is further reason why the analysis as part of Articles 9(1) to 9(10) cannot be carried out as there are no uncovered needs to be analysed.

Analysis was carried out with several sensitivities where the main drivers, and different combinations of drivers, for RES curtailment were removed from the model so that the results could be compared with the base scenario to see their impact on RES curtailment, see Section 8.2 for more information. From these sensitivities, the following results show the impact of Ramping on RES curtailment as required by Article 9(11):

Table 31: Impact of ramping on RES curtailment – Article 9(11)

Scenario WS28 2030	Surplus + Curtailment Dispatch Down, %
Base	7.26
No Ramp	7.16

Therefore, no uncovered needs are arising from the model, and the relative impact on the RES Curtailment is very small. However, this must be caveated that this is in relation to “ramping” as it is defined in the FNA context, which does not reflect the way that ramping margins are considered in the control centre, both from a definitional point of view of how to calculate the need and what is seen as contributing towards meeting the need. Further details on this are outlined in Section 2.5. Therefore, any outcome of analysis for ramping flexibility under the FNA should not be interpreted as having any meaning towards considerations for operating reserves in the SEM.

5.3 Short-term flexibility needs

For the purposes of this analysis, uncovered short term flexibility needs can be defined as when the relevant reserve object in the FNA model has a “shortage” result value and the “provision” result value is zero, meaning that the reserve was fully used and therefore it was not possible for the resources in the model with their relevant characteristics to meet the short term flexibility need. The "shortage" result from the FNA model is actually a reduction in capacity reserved which is akin to the reserve being used, rather than actual uncovered short term flexibility needs.

In particular, there is a specific reserve object added to the model to represent the differences between the day-ahead residual load and the actual residual load, representing that forecast errors upward and downward – as outlined in more detail in Section 2.2. Separately there are also reserve objects added to represent the normal operational reserve categories in the SEM, for Frequency Containment Reserves (FCR) and Replacement Reserves (RR).

As outlined in Section 2.2, based on the modelling approach followed by EirGrid for the purposes of this analysis the task is limited to that in Article 10(10), and therefore the tasks in Articles 10(1) to 10(9) have not been carried out.

5.3.1 Impact of short-term flexibility on RES curtailment

Analysis was carried out with a number of sensitivities where the main drivers, and different combinations of drivers, for RES curtailment were removed from the model so that the results could be compared with the base scenario to see their particular impact on RES curtailment, see Section 8.2 for more information. From these sensitivities, the following results show the impact of short term flexibility (STFlex) on RES curtailment as required by Article 10(10):

Table 32: Impact of short-term flexibility on RES curtailment – Article 10(10)

Scenario WS28 2030	Surplus + Curtailment Dispatch Down, %
Base	7.26
No Short Term Needs incorporated	7.12

Therefore, no uncovered needs are arising from the model, and the relative impact on the RES Curtailment is very small. However, this must be caveated that this is in relation to “short term flexibility” as it is defined in the FNA context, which does not reflect the way that operational reserves are considered in the control centre, both from a definitional point of view of how to calculate the need and what is seen as contributing towards meeting the need. Therefore, any outcome of analysis for short term flexibility under the FNA should not be interpreted as having any meaning towards considerations for operating reserves in the SEM.

5.4 System flexibility needs key messages

From the analysis carried out it is clear that there are significant RES integration flexibility needs in Ireland. This can be observed from the average and total annual dispatch down figures across all weather scenarios and target years. The results for the additional High RES scenarios analysed are higher than the results for the "Base" case scenarios following the ACER Methodology requirements. The results provide insights on the characteristics of RES integration needs in Ireland at different levels of RES installed capacity. Since the total annual dispatch down results of the High RES scenario align closer with what is seen in other separate modelling exercises, such as the ECP results, using this scenario would provide better insights on the impact that adding flexible capabilities has on meeting these RES integration flexibility needs by reducing RES dispatch down, which is considered further in Section 8.

From the analysis carried out, a number of interesting characteristics related to the RES integration flexibility needs have also been observed and give some insights into how additional flexibility could help:

- In 2028 the main driver for dispatch down is transmission network constraints. By 2030, total dispatch down increases as installed RES capacity increases, but the share attributable to network constraints reduces from 88% in 2028 to 45% in 2030 under WS28. This reduction is largely driven by additional transmission network development. However, although constraints account for a lower proportion of dispatch down in 2030, they still represent a substantial share of overall dispatch down volumes.
- Dispatch down driven by surplus renewable generation increases as a proportion of overall dispatch down in scenarios with higher installed RES capacity.
- The volumes of RES dispatch down are greater over the winter months, as might be expected in a system whose renewable energy provision is largely based on wind (which is shown from the relatively higher level of correlation of the RES dispatch down against wind for greater periods of time than against solar or demand).
- When considered as a function of time of day, there is a "double peak" characteristic, which shows dispatch down increasing overnight before the morning load rise, and in the middle of the day before the evening peak. This is somewhat inversely correlated to the average residual load curve. The effect is different during the year depending on levels of demand and extent of RES generation from solar vs wind sources. Summer months are more likely to experience curtailment around the early afternoon (related to higher solar generation and lower demand at those times), whereas winter months are more likely to experience curtailment just before the early morning load rise (related to higher wind generation and lower solar generation overall and higher demand later in the day).
- However, despite these characteristics, it is clear that there are relatively consistent levels of RES dispatch down at all points in time throughout the year. In 2028 this is primarily due to transmission network constraints being present in a majority of hours in the year, but in 2030 there is a consistent level of dispatch down due to system flexibility reasons (and due to renewable surplus in particular).
- RES dispatch down tends to show quite "blocky" characteristics, such that when it arises it tends to be for relatively long durations with relatively high levels of dispatch

down in MW terms. These "blocky" features of the RES dispatch down appear to increase between 2028 and 2030 which appears to be related to the increase in RES capacity and availability.

- While there are individual or shorter duration periods with higher levels of RES dispatch down, the main outcome appears to be lower but still relatively high average levels of RES dispatch down across all different durations, including daily, weekly, monthly, and the durations of the continuous RES dispatch down. This indicates that to use additional flexible resources to meet the RES integration flexibility need in all periods, it may not be effective to just focus on a certain MW amount of shorter duration flexibility to cover the smaller number of periods with larger peaks in RES dispatch down, or a certain MW amount with larger MWh capabilities that can consistently reduce varying levels of dispatch down over longer durations of time. Rather, a combination of both will be needed to meet different needs at different times. Therefore, a mix of flexibility sources is likely to be the most efficient means of meeting these flexibility needs; however, more efficient price signals, and greater participation, in the market may also help to address some of the identified needs (market barriers are discussed in Part D).
- In addition to developing flexibility to reduce RES dispatch down, in order to meet national RES integration targets it will also be important to focus on ensuring that RES installed capacity is developed to levels where its availability in the absence of dispatch down would provide sufficient, or greater than sufficient, levels of penetration that could meet those targets, as it would not be possible to meet these targets through reducing RES dispatch down alone.

On short term and ramping flexibility needs, no uncovered needs were found arising from the modelling approach utilised under the FNA methodology, and their relative impacts on RES dispatch down were small. However, this must be heavily caveated that this is in relation to "short term flexibility" and "ramping" as they are defined in the FNA context, which does not reflect the way that operational reserves and ramping margins respectively are considered in the operation of the power system in Ireland and the SEM, both from a definitional point of view of how to calculate the need, and what is seen as contributing towards meeting the need. Therefore, any outcome of analysis for short term or ramping flexibility under the FNA should not be interpreted as having any meaning towards considerations for operating reserves or ramping margin in Ireland.

6. Transmission Level Needs

Section 3 explains at a high level the approach taken to consider the results of the transmission network flexibility needs in this analysis. Below is a high level summary setting out the level of RES dispatch down appearing in the results from the relevant ECP 2.5 models used.

Table 33: Annual Constraint Dispatch Down, % - Article 12(1), 12(2), 12(3), 12(6)

	WS28		WS4		WS34	
	2028	2030	2028	2030	2028	2030
Base	9.84%	6.05%	9.84%	6.05%	9.84%	6.05%
High RES	10.82%	7.10%	10.82%	7.10%	10.82%	7.10%

Table 34: Average Hourly Constraint Dispatch Down, % - Article 12(1), 12(2), 12(3), 12(6)

	WS28		WS4		WS34	
	2028	2030	2028	2030	2028	W2030
Base	8.94%	5.09%	8.94%	5.09%	8.94%	5.09%
High RES	9.66%	6.23%	9.66%	6.23%	9.66%	6.23%

Additional results considering the transmission level needs are outlined in Section 5.1 (considering the transmission level needs included within the RES integration needs through fine-tuning using the approach explained in Section 2.4 and highlighting some of the particular characteristics of transmission network flexibility needs in Section 5.1.5 and 5.1.6) and Section 8.

6.1 Transmission network flexibility needs key messages

Due to the level of dispatch down resulting from transmission network reason, these results were included in the fine-tuning of RES integration flexibility needs results. More insights on the impact of transmission network flexibility needs on these results can be found in those relevant sections of the report. In summary, however, the results indicate a relatively consistent level of RES dispatch down attributable to transmission network congestion across both target years. This is particularly evident in 2028, when transmission congestion is the predominant driver of RES dispatch down. By 2030, both the volume and proportion of RES dispatch down attributable to transmission congestion reduce, largely as a result of planned network development. Flexible resources could potentially help address RES dispatch down due to transmission network needs. For instance, if flexible resources were developed in areas where RES dispatch down is caused by transmission network congestion, they could help to resolve that issue at relevant times and also help reduce wider system RES dispatch down. However, this should be seen as a complementary action to network development actions which are the primary means through which such congestion and RES dispatch down could be resolved.

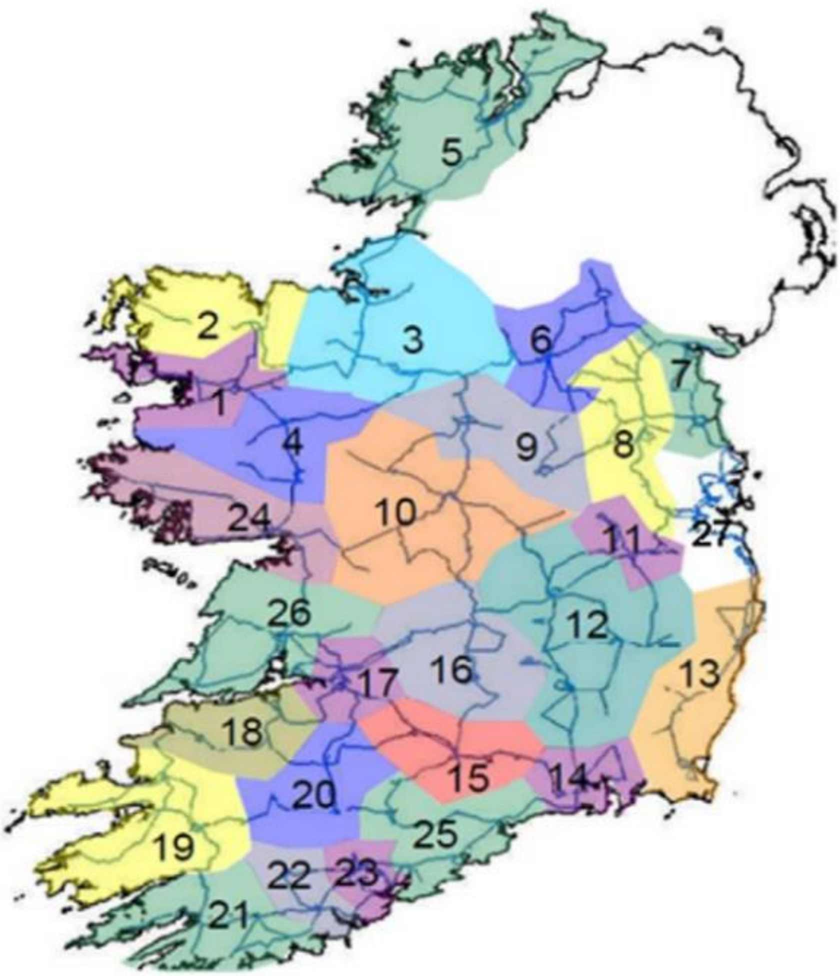
7. Distribution Level Needs

7.1 Zone level Flexibility Needs – explanation

This section outlines the DSO identified flexibility needs, developed in accordance with the methodology described in the Methodology section 4. It presents both the analytical findings and guidance on how to interpret them, ensuring transparency in how zone-level flexibility needs have been derived. The section provides context for each zone's analysis and how the results should be read within the broader framework of the Flexibility Needs Analysis.

There are a total of 27 Zones across Ireland as per the map below (zone 27 is the greater Dublin Area. For the purpose of this chapter, the Dublin area is further broken down within the zonal summary).

Figure 43: Geographic representation of 27 Zones



The flexibility needs identified are those driven by Distribution System congestions within Ireland and are as called for in Article 11 of the ACER Methodology. The flexibility needs are identified largely in terms of option 2.a of Article 11 and provide the summation of local maximum values of power (MW) and energy (MWh) during the time blocks identified. Where the flexibility needs are extensive and variable across the whole year, the total MWh of need may include times outside the specified time blocks. As a result of how the distribution system is operated these needs are not impacted by cross-border or interconnection contributions.

The needs are based on a number of assumptions – which are detailed in the methodology statement – but primarily related to the likely load growth across each of the regions being reported.

For each zone under section 7.3, the report incorporates:

- A geographic map showing the zone boundary and the count of 110 kV and 38 kV stations located within it.
- Flexibility percentage tables summarising the zone-level flexibility contribution.
- A high-level table detailing station-specific flexibility needs (MW/MWh by target year and related reinforcement information).

7.1.1 Description of the ACER Methodology table parameters

The format of the flexibility needs data in the appendices included in the report is aligned with Table 15 and Table 17 of Annex 2 of the ACER Methodology. These tables include the following key headings.

Table 35: description of the ACER Methodology table parameters

Term	Definition
Direction of the need	The direction of need in the tables is always upward. More detail on this in the methodology chapter. Upward flexibility need is defined (within the ACER Methodology) as a need whose solution requires either increasing injection into the network or decreasing demand from the network
Target Years	The two 'Target Years' which were agreed are 2028 and 2030. The results in this report are limited to the years where there is a need identified i.e. where a need will not arise until 2030, results are only shown for 2030. Where a need is identified in 2028, but a capital project delivered

Term	Definition
	between 2028 and 2030 will remove the need, results are only shown for 2028.
Time Block	The 'Time Block' represents the period during which the need predominantly occurs. It is worth noting that – in some cases – some level of need has been identified outside these specific time blocks.
Reasoning to define a time block	As flexibility needs were determined based on station congestion – at 110kV or 38kV – the 'Reasoning to define a time block' will always reflect Congestion at station level.
Spatial granularity	Station at which the need is identified. As reporting will be within a zone this will also provide a geographical reference.
Voltage level of congestion or voltage issue	The voltage level of congestion has been identified. As set out in the methodology chapter (section 4.1 and section 4.4), flexibility needs due to voltage issues have not been identified.
Type of value/Network Flexibility Needs: Total energy over the entire time block	'Total energy over the entire time block' represents the MWh need over the entire year (2028 or 2030) at the specific station.
Type of value/ Network Flexibility Needs: Summation of Maximum Power	'Summation of Maximum Power' represents the peak MW need at each station.
Share of downward flexibility needs pertaining to RES generation curtailment	Not included.

Term	Definition
Expected contractual means to access flexibility	'Expected contractual means to access flexibility' identifies how ESB Networks intends to access flexibility – which will be via procurement of flexible services and/or entering into flexible connection agreements with customers requesting a new connection or increased import capacity.

7.2 Results on a geographic basis and key findings

7.2.1 Key Findings

Following completion of the analysis there are some key findings which should be noted:

1) Overall distribution flexibility needs

Table 36 sets out the overall flexibility needs identified as an absolute value, and also as a percentage of the all-island annual consumption predicted for the target years.

Table 36: Flexibility needs in context of overall System Demand

	2028	2030
Ireland annual total demand in GWh - per All-Island Resource Adequacy Assessment Report	41,900	44,600
Flexibility Needs in GWh	58	53
Flexibility Needs as a % of annual consumption	0.14%	0.12%
Flexibility Needs in MW	234	226

The following should also be noted when considering these figures:

- At the time of writing, ESB Networks has no live contracts for flexibility services. While a flexible connection agreement has been issued, it has not yet been accepted. On that basis, all needs are deemed to be 'uncovered'.
- The absolute volume of flexibility services required remains significant, despite representing a relatively small proportion of annual electricity consumption.
- Identified flexibility requirements reduce between 2028 and 2030 primarily due to capital works scheduled for completion during this period, despite continued load growth over the period.

2) Impact of Capital Programme to end 2030

As noted in the Methodology Chapter (Section 4), where capital works are scheduled to be delivered prior to the target years and those works were assessed as addressing the station congestion, flexibility needs were not identified as being required.

The table below provides a metric of stations excluded from detailed flexibility assessment due to planned works scheduled before the end of 2028, and stations where flexibility needs were not listed due to works scheduled prior to 2030.

As can be seen by the number of stations included in table 37 below, there is an extensive capital programme to be delivered in PR6.

Table 37: Stations excluded from flexibility assessment

	Stations not assessed in detail due to works scheduled pre end 2028	Needs not listed due to works scheduled pre end 2030
110kV/38kV stations	13	2
110kV/MV stations	2	0
38kV/MV stations	46	26

3) Future Capital Programme

In a number of locations the identified flexibility needs are over a long continuous duration. Delivering flexibility services for long durations is expected to be challenging for Flexible Service Assets (FSA). For example, where services are based on batteries, there will be a need to recharge. For this reason where a continuous need of >= five hours is identified, the location in question will be noted for prioritisation of capital works.

7.2.2 Number of distribution stations assessed and where flexibility needs have been identified

The purpose of this section is to give a visual representation of the number of distribution stations countrywide and also the number of stations where flexibility needs have been identified.

Figure 44 sets out the numbers of stations assessed broken down based on voltage. As all distribution stations were assessed, this graph provides the distribution of stations across the country.

Figure 44: Substation Distribution by Planner Zones and Voltage Levels

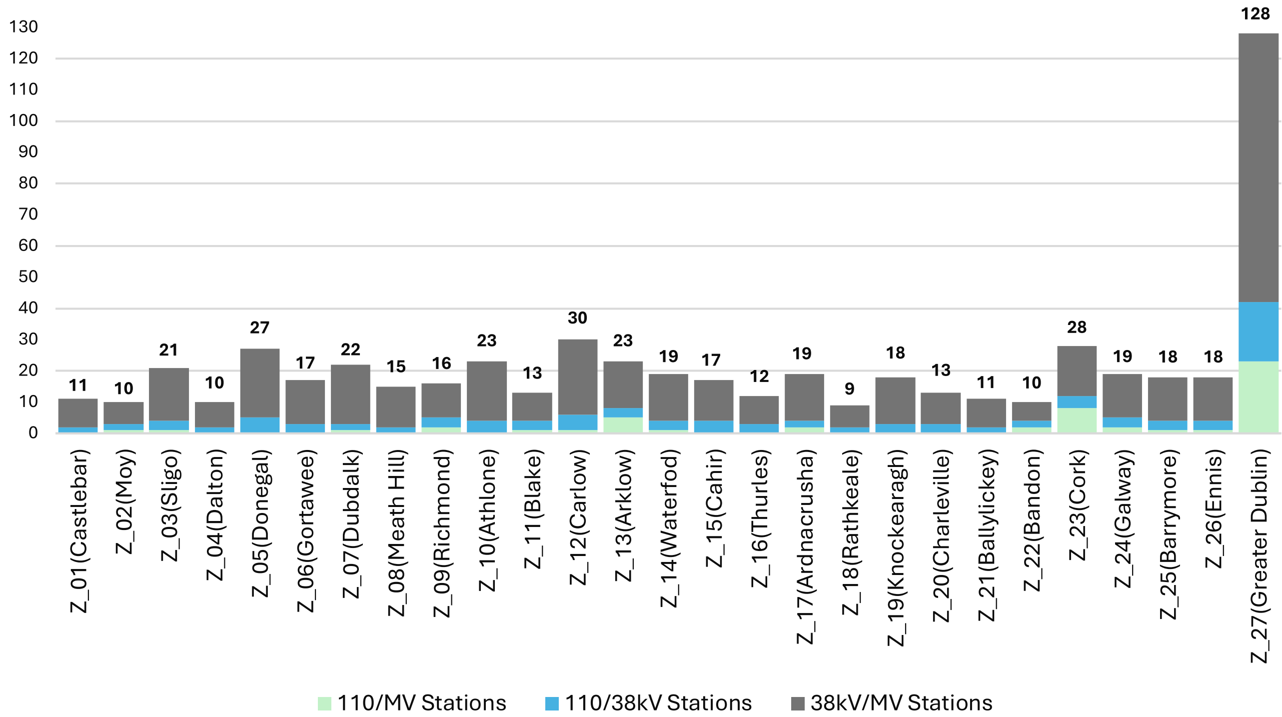
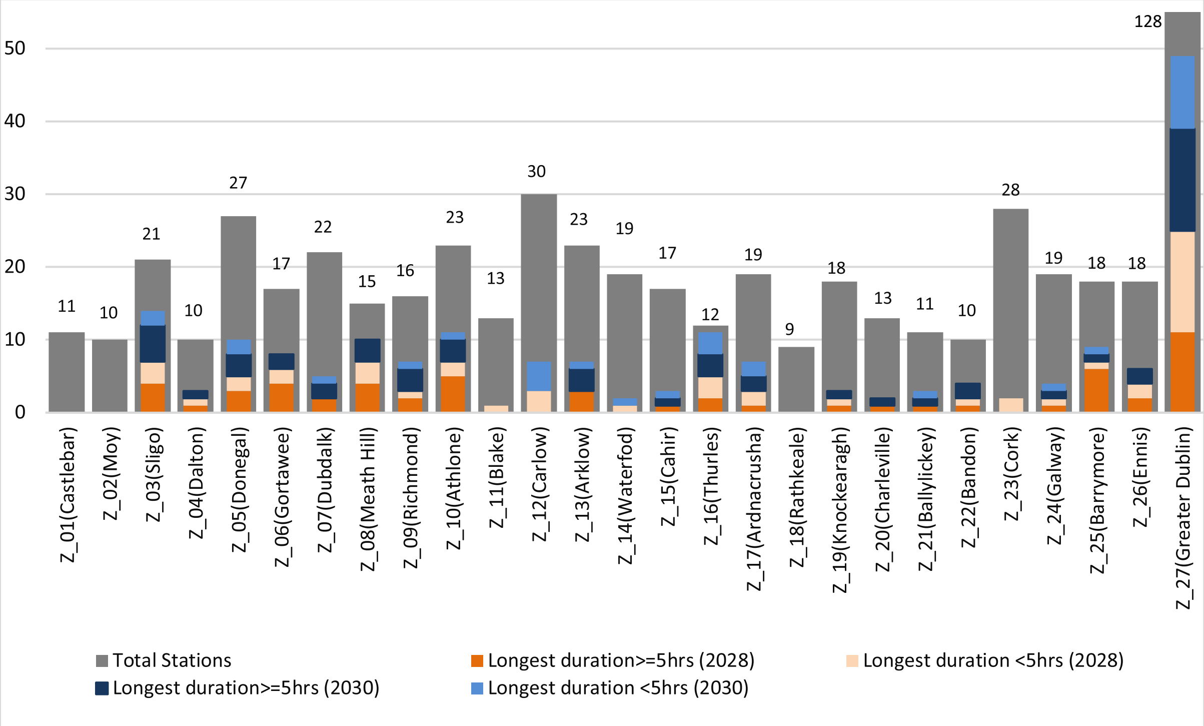


Figure 45 sets out for each of the target years the number of stations where flexibility needs have been identified. This is broken down as follows:

- Where the longest duration of need is > = five hours
- Where the longest duration of need is < five hours

Figure 45: Substation Distribution by Planner Zones and Longest Duration of Flexibility Need



The wider stacked bars show the total number of stations (grey bar) in the zone.

Within each bar, smaller segments represent the number of stations requiring flexibility, categorised by duration:

- Five hours or more (orange for 2028 and dark blue for 2030), and
- Less than five hours[39] (light orange for 2028 and light blue for 2030).

For example, in Zone 3 (Sligo),

- There are twenty-one stations across the 110kV/38kV, 110kV/MV and 38kV/MV categories (Figures 1 and 2).
- Of the 21 stations in Zone 3 (Sligo), the analysis for 2028 found that:
  - four stations have flexibility needs for five hours or more
  - three stations have flexibility needs for less than five hours
- Similarly, for 2030:
  - five stations have flexibility needs for five hours or more, while two stations have flexibility needs for less than five hours.

[39] Stations that have zero hours of need are not included.

7.2.3 Overall flexibility needs – zone by zone

Table 38 below identifies the total MW and MWh needs identified in each zone as a result of the work undertaken.

Table 38: Total MW and MWh needs identified in each zone

Area	2028			2030		
	MW	MWh	% flexible needs across Zone (MWh)	MW	MWh	% flexible needs across Zone (MWh)
Zone 3 - Tonroe	11	3632	1.41	12	6043	2.28
Zone 4 - Dalton	3	632	0.83	2	1240	3.58
Zone 5 - Donegal	11	2034	0.99	10	2672	1.42
Zone 6 - Gortawee	12	4582	1.62	6	2925	3.62
Zone 7 - Dundalk	5	2692	4.33	6	4266	4.06
Zone 8 - Meath Hill	12	5627	1.81	4	230	0.16
Zone 9 - Richmond	11	1749	1.05	13	3282	1.85
Zone 10 - Athlone	21	2845	0.79	12	2505	1.51
Zone 11 - Blake	1	3	0	0	0	0
Zone 12 - Carlow	2	20	0.01	4	110	0.05
Zone 13 - Arklow	10	591	0.31	13	1342	0.55
Zone 14 - Waterford	1	5	0.01	1	36	0.08
Zone 15 - Cahir	2	328	1.33	3	558	0.47
Zone 16 -Thurles	17	1095	0.56	24	2665	1.03
Zone 17- Ardnacrusha	4	186	0.24	5	285	0.25
Zone 19 - Knockearagh	3	170	0.19	3	348	0.78
Zone 20 - Charleville	1	23	0.05	2	139	0.26
Zone 21- Ballylickey	1	29	0.14	2	74	0.12
Zone 22 - Bandon	4	220	0.39	5	477	0.01
Zone 23 - Cork	3	51	0.06	0	0	0
Zone 24 - Galway	3	508	1.93	3	853	1.84
Zone 25 - Barrymore	23	17698	3.48	2	83	0.09
Zone 26 - Ennis	5	139	0.09	4	155	0.22
Dublin Central	19	2376	0.45	18	3583	0.95
Dublin North	42	10238	0.80	54	17277	1.48
Dublin South	11	683	0.20	18	1863	0.30
Total	**234**	**58156**		**226**	**53010**	
Average % Flexible Needs			**0.89**			**1.04**

There are three zones (Zone 1, 2 and 18) where no flexible needs were identified.

Some locations, most notably within the greater Dublin area, have significantly higher flexibility needs in MWh terms. However, when these needs are expressed as a percentage of annual demand at the stations where flexibility is required[40], the percentage needs across the country vary with the Dublin locations typically being below average.

7.3 Estimated Flexibility Needs per Zone

This section describes the details of identified flexibility needs for all the zones and their respective stations.

For each zone in this section, the report incorporates:

- **A geographic map:** Shows the zone boundary and the count of 110 kV and 38 kV stations located within it.
- **Flexibility percentage tables summarising the zone-level flexibility contribution:** The metrics are provided in both MW and MWh and include total flexibility needs, total peak load across stations where flexibility needs were identified, and the corresponding percentage of flexibility relative to peak load at those stations.
- **A high-level table detailing station-specific flexibility needs:** The table lists all stations where flexibility needs have been identified, specifying the MW and MWh needs for the relevant target years, along with the nature of the need (continuous needs of less than 5 hours, or needs of 5 hours or more). It also includes any station-specific considerations, such as planned reinforcement works and their expected energisation dates.

In line with the ACER Methodology Annex-2 detailed results for each station, including the corresponding time blocks and quantified MW and MWh flexibility needs for specific target years, are provided in the respective Appendix file in Appendix C.

[40] This is an appropriate metric as this reflects the demand of the parties who will be able to provide the flexible service.

7.3.1 Zone 3: Sligo, Tonroe and Carrick On Shannon

Zone 3 is in the North West of Ireland and is supplied from four 110kV Bulk Supply Points at Sligo, Tonroe, Carrick-On-Shannon and Arigna, and seventeen 38kV distribution substations as shown in Figure 46.

Figure 46: Zone 3 110kV and 38kV Distribution Network

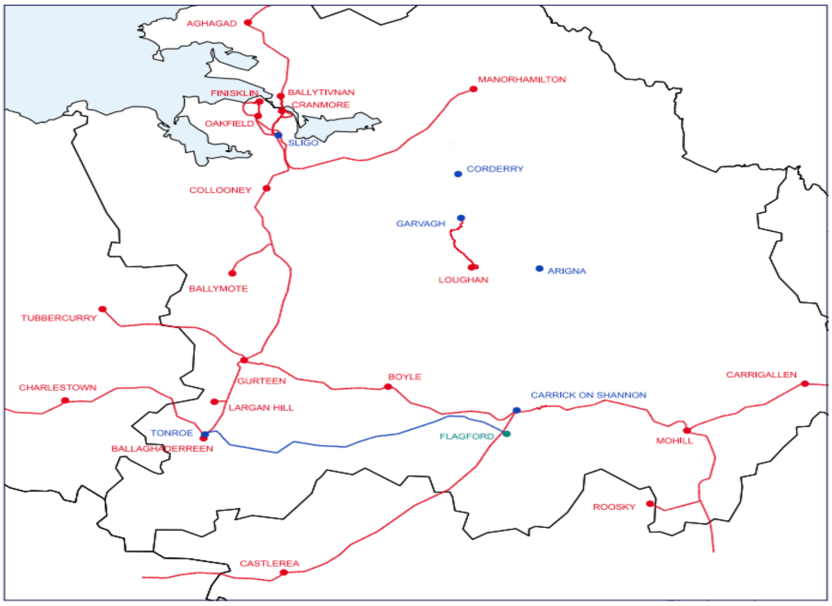


Table 39: Total flexibility needs across Zone 3 for 2028 and 2030

		2028	2030
a	Total Flexibility Need (MW) across zone	10.7 MW	12.45 MW
b	Total Peak Load (MW) across the stations where flexibility needs were identified within the zone	53.35 MW	55.31 MW
c	MW of flexibility need as % of total peak load across the zone **(a/b)**	20.06%	22.51%
d	Total Flexibility Need (MWh) per zone	3632.0 MWh	6043.17 MWh
e	Total Annual Demand (MWh) across the stations where flexibility needs were identified within the zone	257416.91 MWh	265497.57 MWh
f	MWh of flexibility need as % of total annual demand per zone **(d/e)**	1.41%	2.28%

In Zone 3, eight 38kV/MV stations exceed their non-firm loading limits within the agreed horizon and have been subject to a detailed flexibility needs assessment. A high-level summary of the flexibility needs for these stations is provided in Table 40.

Table 40: Zone 3 Per Station Details

<table>
<tr><th>Station Names</th><th>MW - 2028/2030</th><th>MWh - 2028/2030</th><th>Station specific summary</th></tr>
<tr><td>BALLAGHADERREEN 38kV/10kV: [2*5 MVA]</td><td>0.8MW/-l</td><td>8.0MWh/-</td><td>Flexibility needs are listed only for 2028 as a reinforcement project is planned for completion by 2030.</td></tr>
<tr><td>CRANMORE 38kV/10kV: [2*5 MVA]</td><td>-/0.15MW</td><td>-/0.17MWh</td><td>No flexibility needs were identified in 2028
Additionally, no reinforcement projects are planned.</td></tr>
<tr><td>CHARLESTOWN 38kV/10kV: [2*5 MVA]</td><td>0.6 MW /0.8 MW</td><td>4.0 MWh /11.0 MWh</td><td>As there are no planned reinforcement projects due for completion before 2030, flexibility needs were identified for both target years 2028 and 2030.</td></tr>
<tr><td>BALLYMOTE 38kV/10kV: [1*5 MVA]</td><td>0.7 MW /1.0 MW</td><td>12.0 MWh /45.0 MWh</td><td rowspan="5">As there are no planned reinforcement projects due for completion before 2030, flexibility needs were identified for both target years 2028 and 2030

Additionally, the congestion persists for more than five hours at these stations for 2028 and 2030, indicating that flexibility alone may not be a viable long-term solution.</td></tr>
<tr><td>CARRICK ON SHANNON 38kV/10kV: [2*5 MVA]</td><td>3.4 MW /4.1MW</td><td>463.0 MWh /947.0 MWh</td></tr>
<tr><td>COLLOONEY 38kV/20kV: [1*5 MVA]</td><td>2.2 MW /2.6 MW</td><td>897.0 MWh /1583.0 MWh</td></tr>
<tr><td>FINISKLIN 38kV/10kV: [2*5 MVA]</td><td>0.4 MW /0.8 MW</td><td>1.0 MWh /35.0 MWh</td></tr>
<tr><td>MANORHAMILTON 38 V/20kV: [1*5 MVA]</td><td>2.6 MW /3.0 MW</td><td>22247.0 MWh /3422.0 MWh</td></tr>
</table>

Zone 3 is primarily winter driven in its flexibility needs, except for a few 38kV/MV stations, which show flexibility needs across summer months as well as the full year.

7.3.2 Zone 4: Dalton and Cloon

Zone 4 is supplied from two 110kV Bulk Supply Points at Dalton and Cloon and an eight 38kV distribution substations as shown in Figure 47.

Figure 47: Zone 4 110kV and 38kV Distribution Network

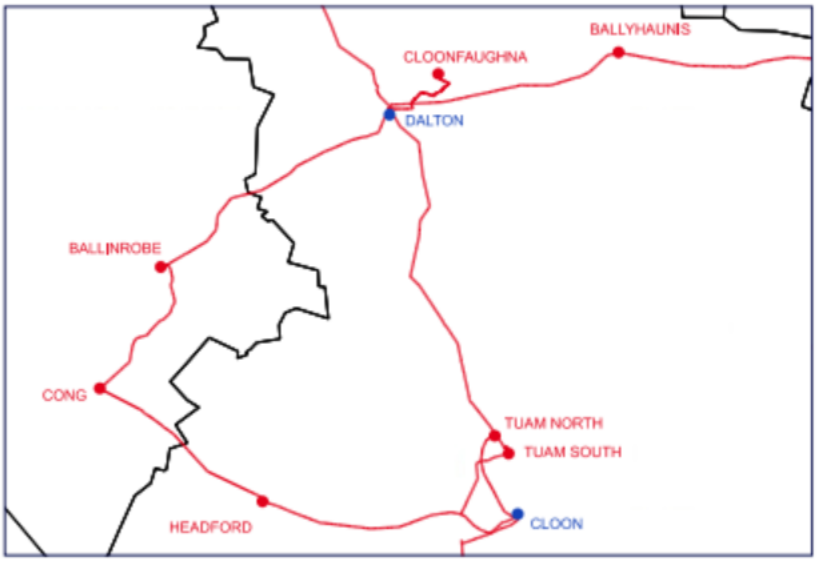


Table 41: Total flexibility needs across Zone 4 for 2028 and 2030

		2028	2030
a	Total Flexibility Need (MW) across zone	2.5 MW	1.6 MW
b	Total Peak Load (MW) across the stations where flexibility needs were identified within the zone	15.26 MW	5.85 MW
c	MW of flexibility need as % of total peak load across the zone (a/b)	16.38%	27.35%
d	Total Flexibility Need (MWh) per zone	632 MWh	1240 MWh
e	Total Annual Demand (MWh) across the stations where flexibility needs were identified within the zone	75918.26 MWh	34649.9 MWh
f	MWh of flexibility need as % of total annual demand per zone (d/e)	0.83%	3.58%

Only two 38kV stations in Zone 4 exceed their non-firm loading limits within the agreed horizon and have been subject to detailed flexibility needs assessment. A high-level summary of the flexibility needs for these stations is provided in Table 42.

Table 42: Zone 4 Per Station Details

Station Names	MW - 2028/2030	MWh - 2028/2030	Station specific summary
TUAM NORTH 38kV/10kV: [2*5 MVA]	1.2 MW/-	11.0 MWh/-	Flexibility needs are listed only for 2028 as a reinforcement project is planned for completion by 2030
TUAM SOUTH 38kV/10kV: [1*5 MVA]	1.3 MW /1.6 MW	621.0 MWh /1240.0 MWh	As there are no planned reinforcement projects due for completion before 2030, flexibility needs were identified for both target years 2028 and 2030

Zone 4 shows a predominantly winter driven flexibility needs up to 2028, transitioning to a full year need thereafter as network conditions evolve.

7.3.3 Zone 5: Donegal

Zone 5 is supplied from five 110kV Bulk Supply points at Letterkenny, Trillick, Ardnagappary, Binbane and Cathleen's Falls and a twenty two 38 kV distribution substations shown in Figure 48.

Figure 48: Zone 5 110kV and 38kV Distribution Network

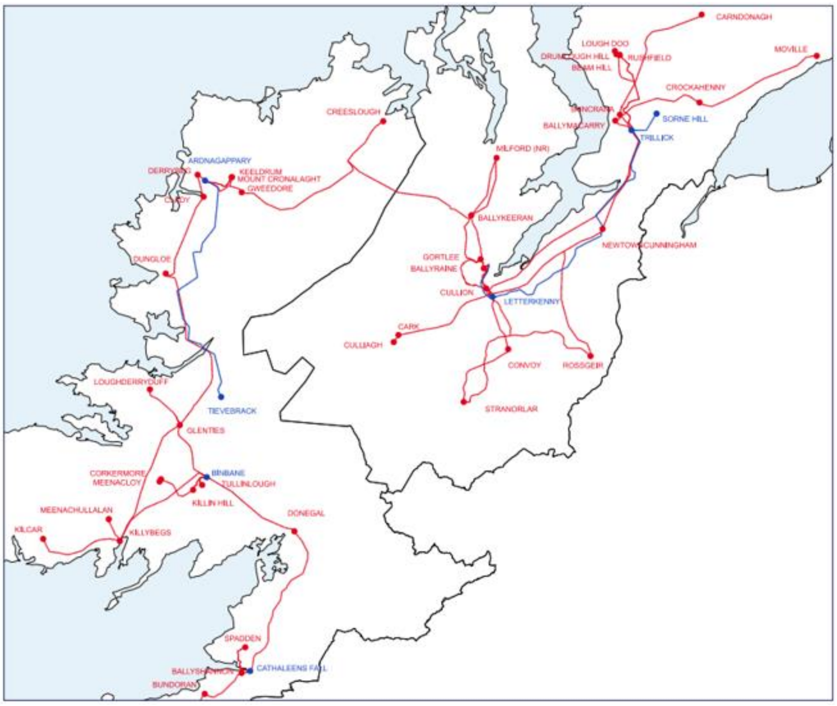


Table 43: Total flexibility needs across Zone 5 for 2028 and 2030

		2028	2030
a	Total Flexibility Need (MW) across zone	10.6 MW	9.58 MW
b	Total Peak Load (MW) across the stations where flexibility needs were identified within the zone	49.15 MW	43.68 MW
c	MW of flexibility need as % of total peak load across the zone (a/b)	21.57%	21.93%
d	Total Flexibility Need (MWh) per zone	2034 MWh	2671.55 MWh

e	Total Annual Demand (MWh) across the stations where flexibility needs were identified within the zone	205976.54 MWh	188160.85 MWh
f	MWh of flexibility need as % of total annual demand per zone (d/e)	0.99%	1.42%

Only six 38 kV stations in Zone 5 exceed their non-firm loading limits within the agreed horizon and have been subject to a detailed flexibility needs assessment. A high-level summary of the flexibility needs for these stations is provided in Table 44.

Table 44: Zone 5 Per Station Details

<table>
<tr><th>Station Names</th><th>MW - 2028/2030</th><th>MWh - 2028/2030</th><th>Station specific summary</th></tr>
<tr><td>BALLYRAINE 38kV/10kV: [1*5MVA & 1*10MVA]</td><td>1.9 MW/ 2.5 MW</td><td>198.0 MWh/ 424.0 MWh</td><td rowspan="3">As there are no planned reinforcement projects due for completion before 2030, flexibility needs were identified for both target years 2028 and 2030.

Additionally, the congestion persists for more than five hours at these stations for 2028 and 2030, indicating that flexibility alone may not be a viable long-term solution.</td></tr>
<tr><td>BUNCRANA 38kV/20kV: [2*5MVA][41]</td><td>1.3MW/ 1.8MW</td><td>17.0 MWh/ 45.0 MWh</td></tr>
<tr><td>CULLION 38kV/10kV: [2*5MVA]</td><td>3.7MW/ 4.4MW</td><td>1407.0 MWh/ 2194.0 MWh</td></tr>
<tr><td>DUNGLOE 38kV/10kV: [1*5MVA]</td><td>0.4 MW / 0.7 MW</td><td>2.0 MWh/ 8.0 MWh</td><td>As there are no planned reinforcement projects due for completion before 2030, flexibility needs were identified for both target years 2028 and 2030.</td></tr>
<tr><td>GLENTIES 38kV/10kV: [1*5MVA]</td><td>-/ 0.18 MW</td><td>-/ 0.55 MWh</td><td>No flexibility needs were identified in 2028.</td></tr>
</table>

[41] Due to substantial data gaps (zero/negligible readings) in the 2024 historical SCADA dataset, the detailed assessment was completed using the full 2025 SCADA data for this station.

			Additionally, no reinforcement projects are planned.
MILFORD (NR) 38kV/10kV: [2*5MVA]	3.3 MW/-	410.0 MWh/-	Flexibility needs are listed only for 2028 as a reinforcement project is planned for completion by 2030. Additionally, the congestion persists for more than five hours at this station for 2028 and 2030, indicating that flexibility alone may not be a viable long-term solution.

Zone 5 is primarily winter driven in its flexibility needs, for the months of October, November, December, January and February.

7.3.4 Zone 6: Gortawee, Shankill and Lisdrum

Zone 6 is supplied from three 110kV Bulk Supply points at Gortawee, Shankill and Lisdrum, and fourteen 38kV distribution substations as shown in Figure 49.

Figure 49: Zone 6 110kV and 38kV Distribution Network

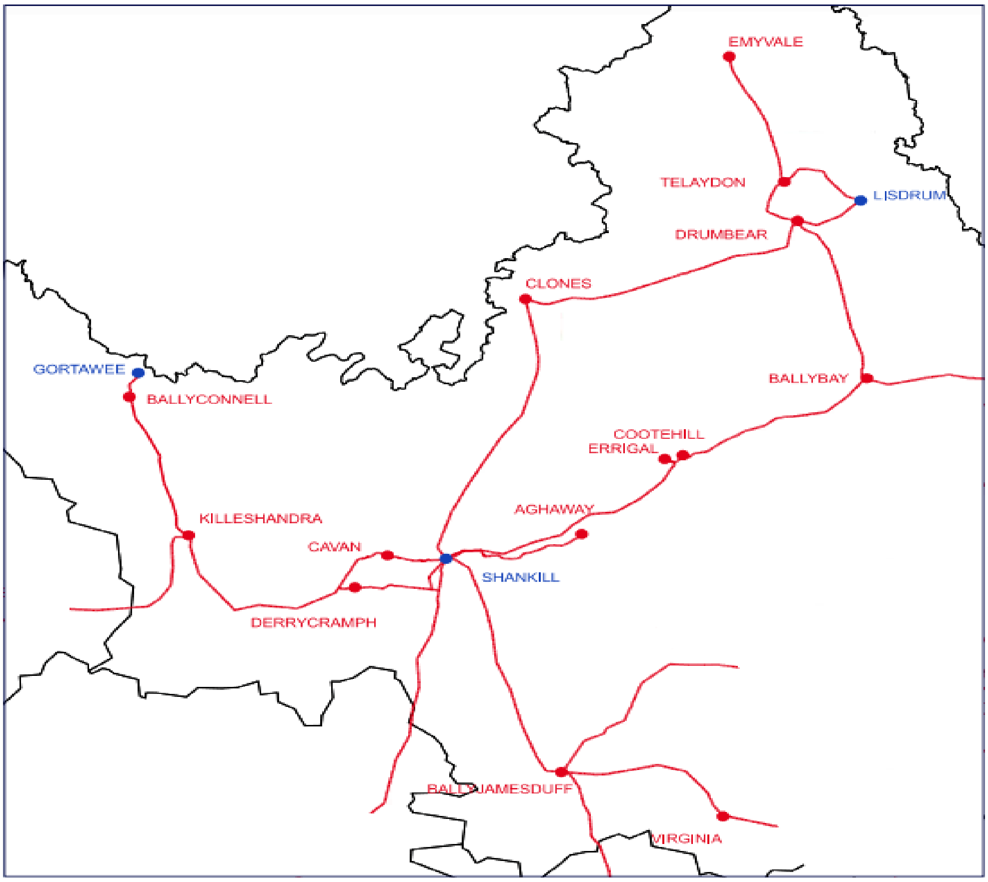


Table 45: Total flexibility needs across Zone 6 for 2028 and 2030

		2028	2030
a	Total Flexibility Need (MW) across zone	12.36 MW	5.9 MW
b	Total Peak Load (MW) across the stations where flexibility needs were identified within the zone	59.34 MW	18.71 MW
c	MW of flexibility need as % of total peak load across the zone (a/b)	20.83%	31.53%
d	Total Flexibility Need (MWh) per zone	4582.2 MWh	2925 MWh

e	Total Annual Demand (MWh) across the stations where flexibility needs were identified within the zone	283284.47 MWh	80854.3 MWh
f	MWh of flexibility need as % of total annual demand per zone (d/e)	1.62%	3.62%

Since there are multiple reinforcement projects scheduled for this zone, most occurring between 2028 and 2030 and resulting in a significant reduction in flexibility needs in 2030 compared with 2028 (as it is expected that the projects will address the station congestion).

In Zone 6, five 38kV/MV stations exceed their non-firm loading limits within the agreed horizon and have been subject to a detailed flexibility needs assessment. A high-level summary of the flexibility needs for these stations is provided in Table 46.

Table 46: Zone 6 Per Station Details

<table>
<tr><th>Station Names</th><th>MW - 2028/2030</th><th>MWh - 2028/2030</th><th>Station specific summary</th></tr>
<tr><td>CAVAN 38kV/10kV: [1*10 MVA] [42]</td><td>0.8 MW/ -</td><td>38.0 MWh/ -</td><td rowspan="3">Flexibility needs are listed only for 2028 as a reinforcement project is planned for completion by 2030.

Additionally, the congestion persists for more than five hours at these stations for 2028 and 2030, indicating that flexibility alone may not be a viable long-term solution.</td></tr>
<tr><td>CAVAN 38 kV/20kV: [1*10 MVA] [41]</td><td>4.4 MW/ -</td><td>2493.0 MWh/ -</td></tr>
<tr><td>DRUMBEAR 38 kV/10kV: [2*5 MVA]</td><td>2.0 MW/ -</td><td>197.0 MWh/ -</td></tr>
</table>

[42] This station comprises of two transformers operating at distinct medium-voltage levels, 10kV and 20kV. Consequently, the assessment was conducted separately for each transformer, treating them as independent, standalone units

DERRYCRAMPH 38 kV/10kV: [2*5 MVA]	0.26 MW/ -	0.2 MWh/ -	Flexibility needs are listed only for 2028 as a reinforcement project is planned for completion by 2030
EMYVALE 38 kV/20kV: [1*5 MVA]	0.9 MW/ 1.2 MW	6.0 MWh/ 30.0 MWh	As there are no planned reinforcement projects due for completion before 2030, flexibility needs were identified for both target years 2028 and 2030 Additionally, the congestion persists for more than five hours at these stations for 2028 and 2030, indicating that flexibility alone may not be a viable long-term solution.
FINEA 38 kV/20kV: [2*5 MVA]	4.0 MW/ 4.7 MW	1848.0 MWh/ 2895.0 MWh	

Zone 6 is primarily winter driven in its flexibility needs, except for Cavan 38 kV/MV, which shows the highest MW/MWh flexibility need within the zone in 2028 and requires flexibility across the full year.

7.3.5 Zone 7: Dundalk and Drybridge

Zone 7 is supplied from three 110kV Bulk Supply points at three 110kV Bulk Supply points at Mullagharlin, Dundalk and Drybridge, and a nineteen 38kV distribution Substations as shown in Figure 50.

Figure 50: Zone 7 110kV and 38kV Distribution Network

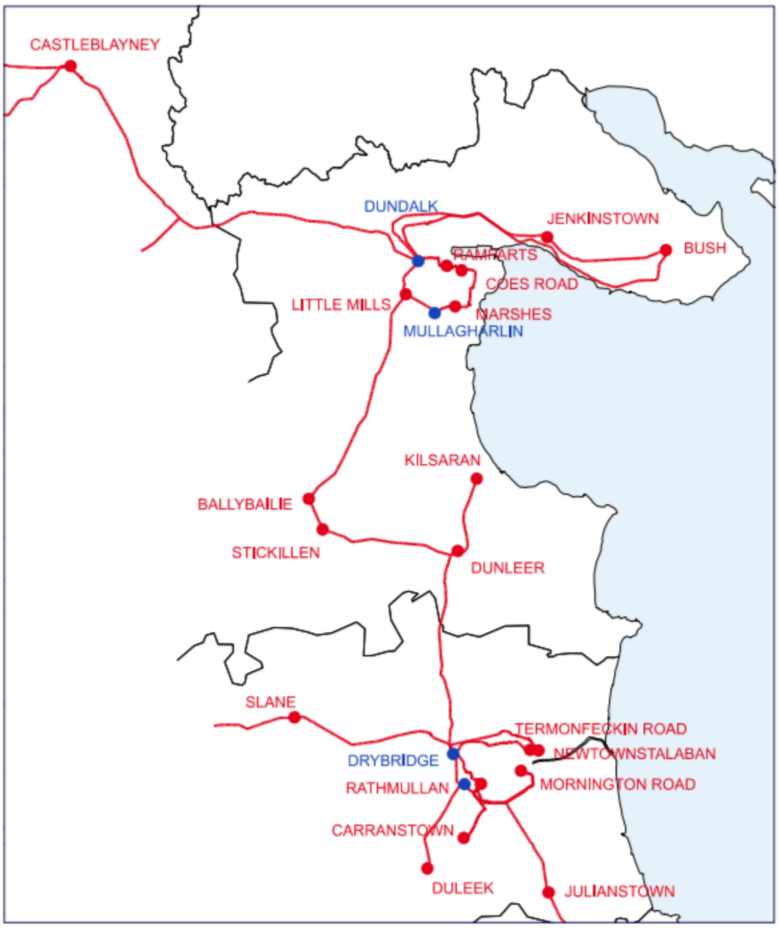


Table 47: Total flexibility needs across Zone 7 for 2028 and 2030

		2028	2030
a	Total Flexibility Need (MW) across zone	5.2 MW	6.11 MW
b	Total Peak Load (MW) across the stations where flexibility needs were identified within the zone	13.74 MW	23.25 MW
c	MW of flexibility need as % of total peak load across the zone (a/b)	37.85%	26.28%

d	Total Flexibility Need (MWh) per zone	2692 MWh	4266 MWh
e	Total Annual Demand (MWh) across the stations where flexibility needs were identified within the zone	62213.98 MWh	105014.70 MWh
f	MWh of flexibility need as % of total annual demand per zone (d/e)	4.33%	4.06%

In Zone 7, three 38kV/MV stations exceed their non-firm loading limits within the agreed horizon and have been subject to a detailed flexibility needs assessment. A high-level summary of the flexibility needs for these stations is provided in Table 48.

Table 48: Zone 7 Per Station Details

Station Names	MW - 2028/2030	MWh - 2028/2030	Station specific summary
LITTLE MILLS 38kV/10kV: [1*5MVA]	2.4 MW / 2.8 MW	1112 MWh / 1752 MWh	As there are no planned reinforcement projects due for completion before 2030, flexibility needs were identified for both target years 2028 and 2030. Additionally, the congestion persists for more than five hours at these stations for 2028 and 2030, indicating that flexibility alone may not be a viable long-term solution.
BALLYBAILIE 38kV/10kV: [1*5MVA]	2.8 MW / 3.3 MW	1580 MWh / 2514 MWh	
DUNLEER 38kV/10kV: [2*5MVA]	- / 0.01 MW	- / 0.0047 MWh	No flexibility needs were identified in 2028. Additionally, no reinforcement projects are planned.

Zone 7 is primarily winter driven in its flexibility needs.

7.3.6 Zone 8: Meath Hill and Navan

Zone 8 is supplied from two 11kV Bulk Supply points at Meath Hill and Navan, and thirteen 38kV distribution substations as shown in Figure 51.

Figure 51: Zone 8 110kV and 38kV Distribution Network

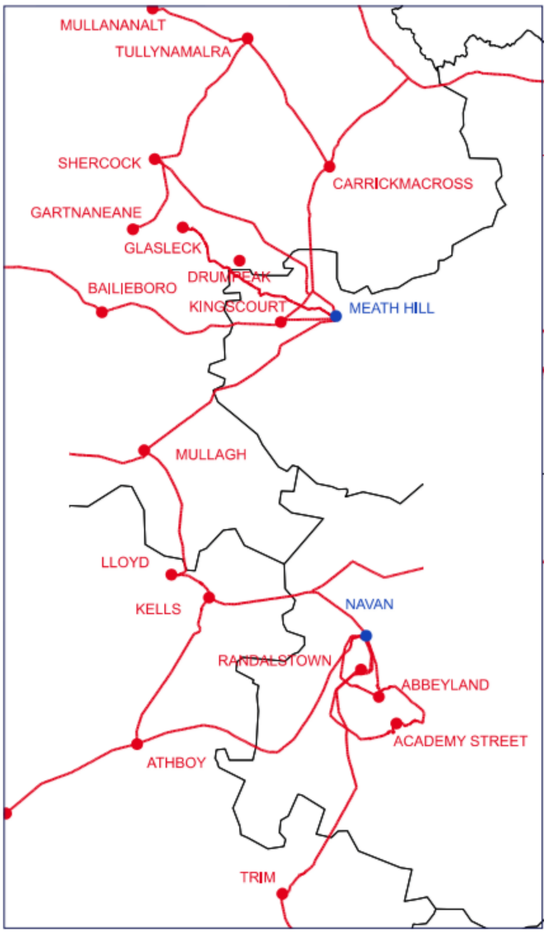


Table 49: Total flexibility needs across Zone 8 for 2028 and 2030

		2028	2030
a	Total Flexibility Need (MW) across zone	12.4 MW	4.4 MW
b	Total Peak Load (MW) across the stations where flexibility needs were identified within the zone	68.12 MW	30.01 MW
c	MW of flexibility need as % of total peak load across the zone (a/b)	18.20%	14.66%
d	Total Flexibility Need (MWh) per zone	5627 MWh	230 MWh

e	Total Annual Demand (MWh) across the stations where flexibility needs were identified within the zone	311177.45 MWh	143551.97 MWh
f	MWh of flexibility need as % of total annual demand per zone (d/e)	1.81%	0.16%

Since there are multiple reinforcement projects scheduled for this zone, most occurring between 2028 and 2030 and resulting in a significant reduction in flexibility needs in 2030 compared with 2028 (as it is expected that the projects will address the station congestion).

In Zone 8, four 38kV/MV stations exceed their non-firm loading limits within the agreed horizon and have been subject to a detailed flexibility needs assessment. A high-level summary of the flexibility needs for these stations is provided in Table 50.

Table 50: Zone 8 Per Station Details

Station Names	MW - 2028/2030	MWh - 2028/2030	Station specific summary
ACADEMY STREET 38kV/10kV: [1*5MVA] [43]	0.9 MW / -	2.0 MWh / -	Flexibility needs are listed only for 2028 as a reinforcement project is planned for completion by 2030 Additionally, the congestion persists for more than five hours at these stations for 2028 and 2030, indicating that flexibility alone may not be a viable long-term solution.
ACADEMY STREET 38kV/20kV: [2*5MVA][42]	6.7 MW / -	5503.0 MWh / -	
TRIM 38kV/10kV: [2*5MVA][42]	1.6 MW / -	45.0 MWh / -	
TRIM 38kV/20kV: [1*5MVA][42]	0.9 MW / -	17.0 MWh / -	
CARRICKMACROSS 38kV/10kV: [2*10MVA]	0.5 MW / 1.7 MW	1.0 MWh / 37.0 MWh	

[43] These stations comprise of two transformers operating at distinct medium-voltage levels, 10kV and 20kV. Consequently, the assessment was conducted separately for each transformer, treating them as independent, standalone units

ATHBOY 38kV/10kV: [1*5MVA][42]	0.7 MW / 1.1 MW	13.0 MWh / 63.0 MWh	As there are no planned reinforcement projects due for completion before 2030, flexibility needs were identified for both target years 2028 and 2030. Additionally, the congestion persists for more than five hours at this station for 2028 and 2030, indicating that flexibility alone may not be a viable long-term solution.
ATHBOY 38kV/20kV: [1*5MVA][42]	1.1 MW / 1.6 MW	46.0 MWh / 130.0 MWh	

Zone 8 is primarily winter driven in its flexibility needs.

7.3.7 Zone 9: Richmond, Lanesboro and Mullingar

Zone 9 is supplied from four 110kV Bulk Supply points at Richmond, Lanesboro, Mullingar (110kV/38kV and 110kV/MV) and Dunfirth, and eleven 38kV distribution substations as shown in Figure 52.

Figure 52: Zone 9 110kV and 38kV Distribution Network

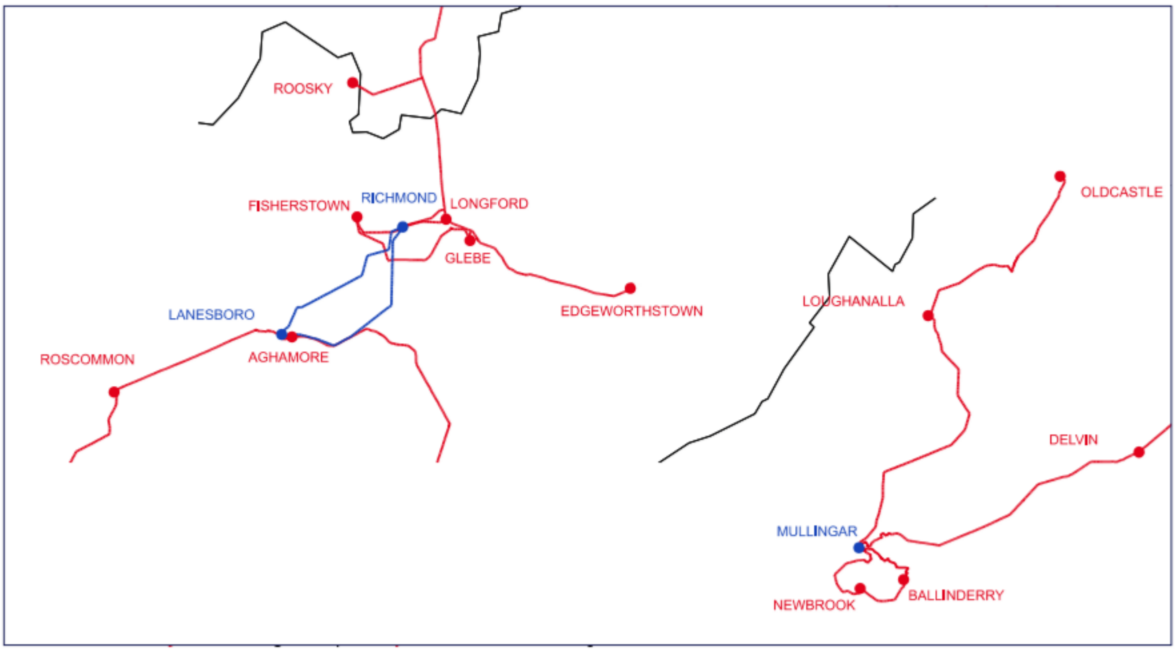


Table 51: Total flexibility needs across Zone 9 for 2028 and 2030

		2028	2030
a	Total Flexibility Need (MW) across zone	10.5 MW	12.83 MW
b	Total Peak Load (MW) across the stations where flexibility needs were identified within the zone	40.28 MW	42.74 MW
c	MW of flexibility need as % of total peak load across the zone (a/b)	26.07%	30.01%
d	Total Flexibility Need (MWh) per zone	1749 MWh	3282 MWh
e	Total Annual Demand (MWh) across the stations where flexibility needs were identified within the zone	166855.79 MWh	176979.30 MWh
f	MWh of flexibility need as % of total annual demand per zone (d/e)	1.05%	1.85%

In Zone 9, two 38kV/MV stations exceed their non-firm loading limits within the agreed horizon and have been subject to a detailed flexibility needs assessment. A high-level summary of the flexibility needs for these stations is provided in Table 52.

Table 52: Zone 9 Per Station Details

Station Names	MW - 2028/2030	MWh - 2028/2030	Station specific summary
Aghamore 38kV/10kV: [1*5MVA]	- / 0.087 MW	- / 0.75 MWh	As there are no planned reinforcement projects due for completion before 2030, flexibility needs were identified for both target years 2028 and 2030.
Newbrook 38kV/10kV: [1*5MVA]	2.4 MW / 3.0 MW	700.0 MWh / 1411.0 MWh	
Ballinderry 38kV/10kV: [1*10MVA][44]	1.3 MW / 1.89 MW	26.0 MWh /	

[44] This station comprises of two transformers operating at distinct medium-voltage levels, 10kV and 20kV. Consequently, the assessment was conducted separately for each transformer, treating them as independent, standalone units

		106.25 MWh	Additionally, in Newbrook and Ballinderry the congestion persists for more than five hours in 2028 and 2030, indicating that flexibility alone may not be a viable long-term solution.
Ballinderry 38kV/20kV: [1*10MVA][43]	6.8 MW / 7.85 MW	1023.0 MWh / 1765.17 MWh	

Zone 9 is primarily winter driven in its flexibility needs, with a need in July also identified for Aghamore 38kV/MV.

7.3.8 Zone 10: Athlone, Somerset, Dallow and Thornsberry

Zone 10 is supplied from four 110kV Bulk Supply points at Athlone, Somerset, Dallow and Thornsberry, and nineteen 38kV distribution substations as shown in Figure 53.

Figure 53: Zone 10 110kV and 38kV Distribution Network

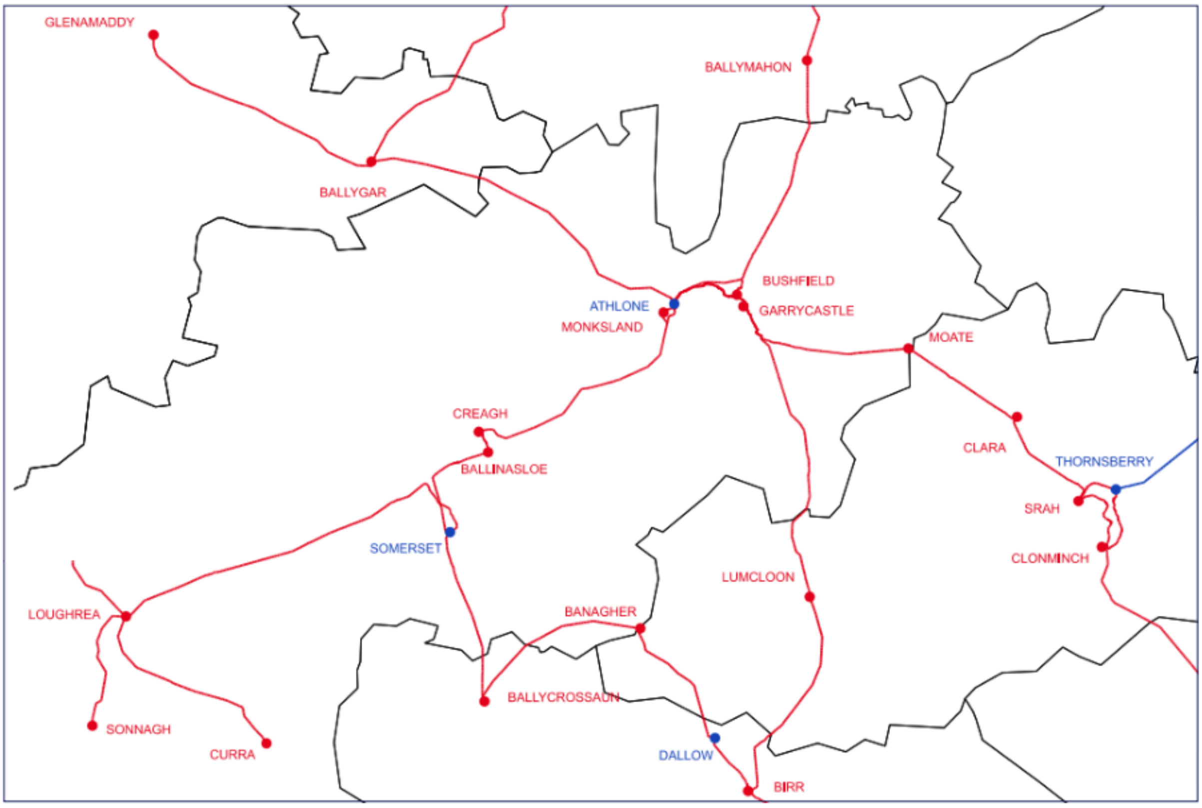


Table 53: Total flexibility needs across Zone 10 for 2028 and 2030

		2028	2030
a	Total Flexibility Need (MW) across zone	20.7 MW	12.3 MW
b	Total Peak Load (MW) across the stations where flexibility needs were identified within the zone	92.92 MW	42.2 MW
c	MW of flexibility need as % of total peak load across the zone (a/b)	22.28%	29.15%
d	Total Flexibility Need (MWh) per zone	2845 MWh	2605 MWh
e	Total Annual Demand (MWh) across the stations where flexibility needs were identified within the zone	360664.58 MWh	171963.54 MWh
f	MWh of flexibility need as % of total annual demand per zone (d/e)	0.79%	1.51%

Since there are multiple reinforcement projects scheduled for this zone, most occurring between 2028 and 2030 and resulting in a significant reduction in flexibility needs in 2030 compared with 2028 (as it is expected that the projects will address the station congestion).

In Zone 10, six 38kV/MV stations and one 110kV/38kV station exceed their non-firm loading limits within the agreed horizon and have been subject to a detailed flexibility needs assessment. A high-level summary of the flexibility needs for these stations is provided in Table 54.

Table 54: Zone 10 Per Station Details

Station Names	MW - 2028/2030	MWh - 2028/2030	Station specific summary
SOMERSET 110kV/38kV: [1*31.5MVA][45]	4.7 MW / -	81.0 MWh / -	Flexibility needs are listed only for 2028 as a reinforcement project is

[45] Flexibility needs listed for this station are the net need assuming that the flexibility from the downstream station Loughrea 38kV/10kV is procured and activated.

			planned for completion by 2030.
LOUGHREA 38kV/10kV: [2*5MVA]	4.2 MW / -	1113.0 MWh / -	Flexibility needs are listed only for 2028 as a reinforcement project is planned for completion by 2030. Additionally, the congestion persists for more than five hours at these stations for 2028 and 2030, indicating that flexibility alone may not be a viable long-term solution.
GLENAMADDY 38kV/20kV: [1*5MVA]	2.0 MW / -	237.0 MWh / -	
CLONMINCH 38kV/10kV: [1*10MVA][46]	3.2 MW / 3.9 MW	905.0 MWh / 1601.0 MWh	As there are no planned reinforcement projects due for completion before 2030, flexibility needs were identified for both target years 2028 and 2030. Additionally, the congestion persists for more than five hours at these stations for 2028 and 2030, indicating that flexibility alone may not be a viable long-term solution.
CREAGH 38kV/20kV: [1*5MVA]	2.6 MW / 3.4 MW	142.0 MWh / 360.0 MWh	
MOATE 38kV/10kV: [1*5MVA]	2.2 MW / 2.6 MW	341.0 MWh / 578.0 MWh	
BIRR 38kV/20kV: [1*10MVA][46]	1.8 MW / 2.4 MW	26.0 MWh / 66.0 MWh	As there are no planned reinforcement projects due for completion before 2030, flexibility needs were

[46] This station comprises of two transformers operating at distinct medium-voltage levels, 10kV and 20kV. Consequently, the assessment was conducted separately for each transformer, treating them as independent, standalone units. In Clonminch there is no overloading on the transformer operating on MV voltage of 20kV. In Birr, there is no overloading on the transformer operating on MV voltage of 10kV

			identified for both target years 2028 and 2030.

Zone 10 is primarily winter driven in its flexibility needs.

7.3.9 Zone 11: Blake, Kilteel and Newbridge

Zone 11 is supplied from four 110kV Bulk Supply points at Newbridge, Blake, Monread and Kilteel, and nine 38kV distribution substations as shown in Figure 54.

Figure 54: Zone 11 110kV and 38kV Distribution Network

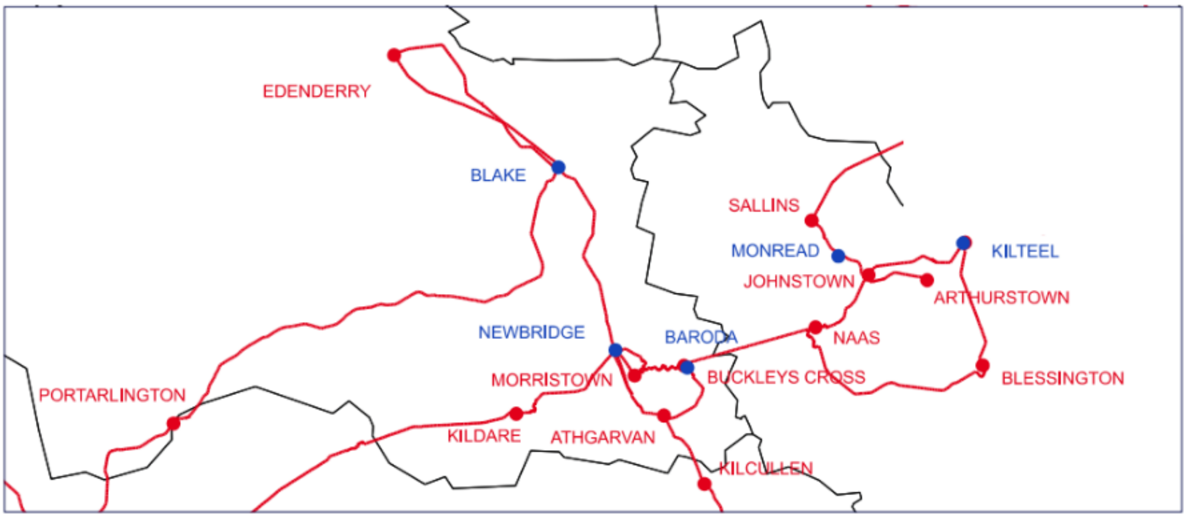


Table 55: Total flexibility needs across Zone 11 for 2028 and 2030

		2028	2030
a	Total Flexibility Need (MW) across zone	0.6 MW	0 MW
b	Total Peak Load (MW) across the stations where flexibility needs were identified within the zone	17.68 MW	0 MW
c	MW of flexibility need as % of total peak load across the zone (a/b)	3.39%	0.00%
d	Total Flexibility Need (MWh) per zone	3 MWh	0 MWh
e	Total Annual Demand (MWh) across the stations where flexibility needs were identified within the zone	88983.01 MWh	0.00 MWh

f	MWh of flexibility need as % of total annual demand per zone (d/e)	0.00%	0.00%

In Zone 11, one 38kV/MV station exceeds its non-firm loading limit within the agreed horizon and has been subject to a detailed flexibility needs assessment. A high-level summary of the flexibility needs for this station is provided in Table 56.

Table 56: Zone 11 Per Station Details

Station Names	MW - 2028/2030	MWh - 2028/2030	Station specific summary
NAAS 38kV/10kV: [2*10MVA]	0.6 MW / -	3.0 MWh / -	Flexibility needs are listed only for 2028 as a reinforcement project is planned for completion by 2030.

Zone 11 is winter driven in its flexibility needs, only requiring flexibility in January.

7.3.10 Zone 12: Carlow, Kilkenny and Portlaoise

Zone 12 is supplied from six 110kV Bulk Supply points at Ballyragget, Carlow, Kilkenny, Athy, Portlaoise and Stratford, and a twenty four 38kV distribution substations as shown in Figure 55.

Figure 55: Zone 12 110kV and 38kV Distribution Network

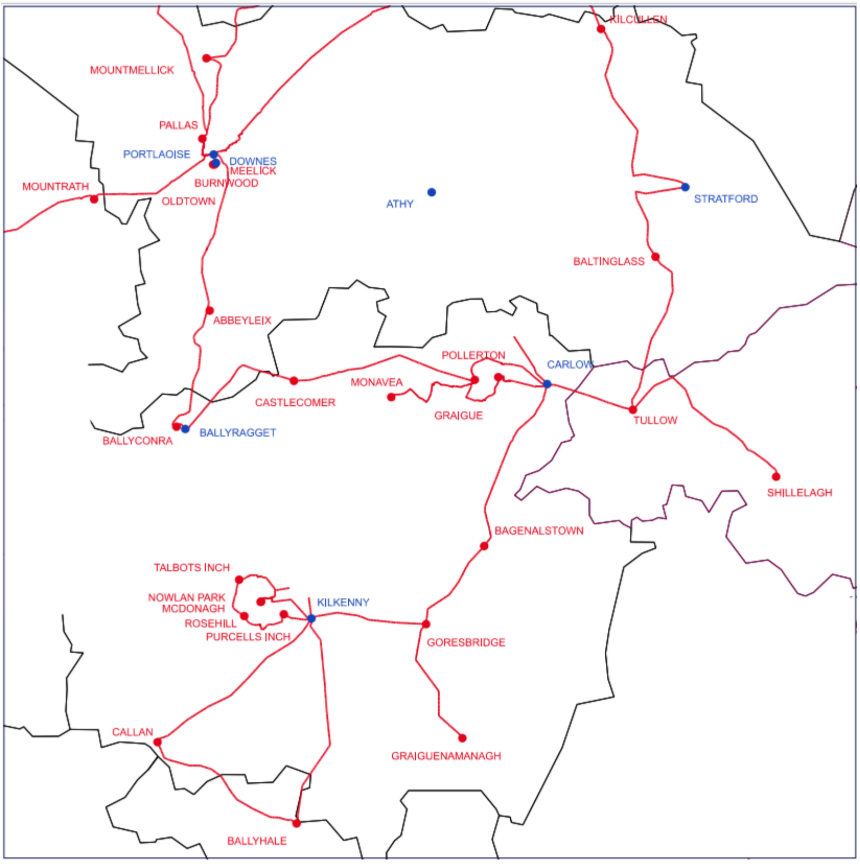


Table 57: Total flexibility needs across Zone 12 for 2028 and 2030

		2028	2030
a	Total Flexibility Need (MW) across zone	2.36 MW	4.47 MW
b	Total Peak Load (MW) across the stations where flexibility needs were identified within the zone	36.98 MW	47.64 MW
c	MW of flexibility need as % of total peak load across the zone (a/b)	6.38%	9.38%

d	Total Flexibility Need (MWh) per zone	20.15 MWh	109.73 MWh
e	Total Annual Demand (MWh) across the stations where flexibility needs were identified within the zone	170879.59 MWh	208423.60 MWh
f	MWh of flexibility need as % of total annual demand per zone (d/e)	0.01%	0.05%

In Zone 12, three 38kV/MV stations and one 110kV/38kV station exceed their non-firm loading limit within the agreed horizon and has been subject to a detailed flexibility needs assessment. A high-level summary of the flexibility needs for these stations is provided in Table 58.

Table 58: Zone 12 Per Station Details

Station Names	MW - 2028/2030	MWh - 2028/2030	Station specific summary
STRATFORD 110kV/38kV: [1*31.5MVA]	1.92 MW / 3.54 MW	12.33 MWh / 82.77 MWh	As there are no planned reinforcement projects due for completion before 2030, flexibility needs were identified for both target years 2028 and 2030.
BALLYHALE 38kV/20kV: [1*5MVA][47]	0.06 MW / 0.29 MW	0.004 MWh / 1.71 MWh	
GRAIGUENAMANAGH 38kV/10kV: [2*2MVA]	0.38 MW / 0.58 MW	7.78 MWh / 25.22 MWh	
CASTLECOMER 38kV/10kV: [2*5MVA]	- / 0.06 MW	- / 0.03 MWh	No flexibility needs were identified in 2028. Additionally, no reinforcement projects are planned.

[47] This station comprises of two transformers operating at distinct medium-voltage levels, 10kV and 20kV. Consequently, the assessment was conducted separately for each transformer, treating them as independent, standalone units. There is no overloading on transformer operating on MV voltage of 10kV.

Zone 12 is primarily winter driven in its flexibility needs.

7.3.11 Zone 13: Arklow and Enniscorthy

Zone 13 is supplied from five 110kV Bulk Supply Points at Arklow, Ballybeg, Banoge, Crane and Wexford, and fifteen 38 kV distribution substations as shown in Figure 56.

Figure 56: Zone 13 110kV and 38kV Distribution Network

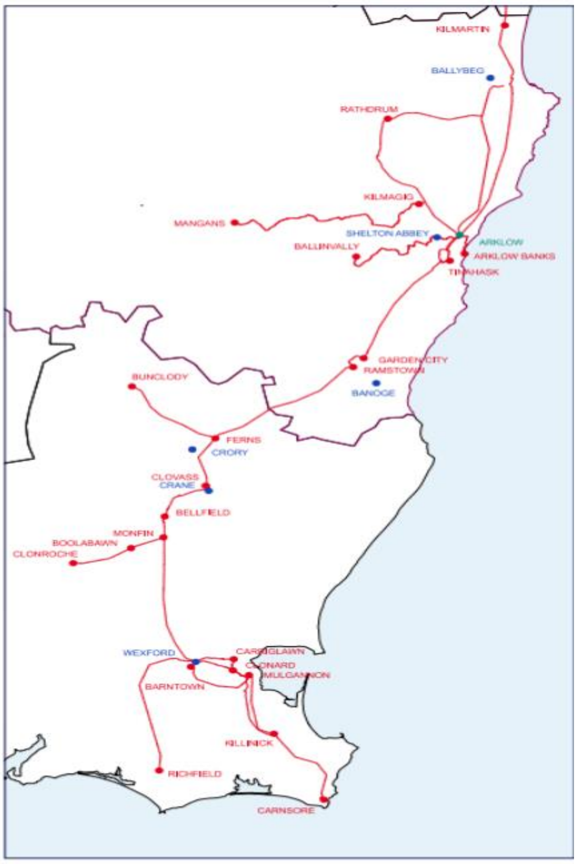


Table 59: Total flexibility needs across Zone 13 for 2028 and 2030

		2028	2030
a	Total Flexibility Need (MW) across zone	9.7 MW	12.5 MWh
b	Total Peak Load (MW) across the stations where flexibility needs were identified within the zone	45.14 MW	56.19 MW
c	MW of flexibility need as % of total peak load across the zone (a/b)	21.49%	22.28%

d	Total Flexibility Need (MWh) per zone	591 MWh	1342 MWh
e	Total Annual Demand (MWh) across the stations where flexibility needs were identified within the zone	192681.97 MWh	245994.05 MWh
f	MWh of flexibility need as % of total annual demand per zone (d/e)	0.31%	0.55%

In Zone 13[48], one 110kV/38kV and three 38kV/MV stations exceed their non-firm loading limits within the agreed horizon and have been subject to a detailed flexibility needs assessment. A high-level summary of the flexibility needs for these stations is provided in Table 60.

Table 60: Zone 13 Per Station Details

Station Names	MW - 2028/2030	MWh - 2028/2030	Station specific summary
CARRIGLAWN-38kV/10kV: [2*5MVA]	- / 0.12 MW	- / 0.10 MWh	No flexibility needs were identified in 2028. Additionally, no reinforcement projects are planned.
CRANE-110kV/38kV: [1*31.5MVA]	8.10 MW / 10.10 MW	498.0 MWh / 1083.0 MWh	As there are no planned reinforcement projects due for completion before 2030, flexibility needs were identified for both target years 2028 and 2030. Additionally, the congestion persists for more than five hours at these stations for
KILMARTIN-38kV/10kV[49]: [1*5MVA]	0.70 MW / 1.10 MW	35.0 MWh / 106.0 MWh	
RATHDRUM-38kV/10kV: [1*5MVA]	0.90 MW / 1.20 MW	58.0 MWh / 153.0 MWh	

48 There is one non-SCADAfied station (Kilmagig 38kV/10kV) within zone 13, therefore no flexibility need assessment has been performed for this station.

49 Due to substantial data gaps (zero/negligible readings) in the 2024 historical SCADA dataset for this station, the detailed assessment was completed using the full 2025 SCADA data for this station.

			2028 and 2030, indicating that flexibility alone may not be a viable long-term solution.

Zone 13 is primarily winter driven in its flexibility needs, with a need in May and June also identified for Kilmartin-38kV/MV.

7.3.12 Zone 14: Waterford, Butlerstown and Great Island

Zone 14 is supplied from four 110kV Bulk Supply points at Waterford, Butlerstown, Killoteran and Great Island, and fifteen 38kV distribution substations as shown in Figure 57.

Figure 57: Zone 14 110kV and 38kV Distribution Network

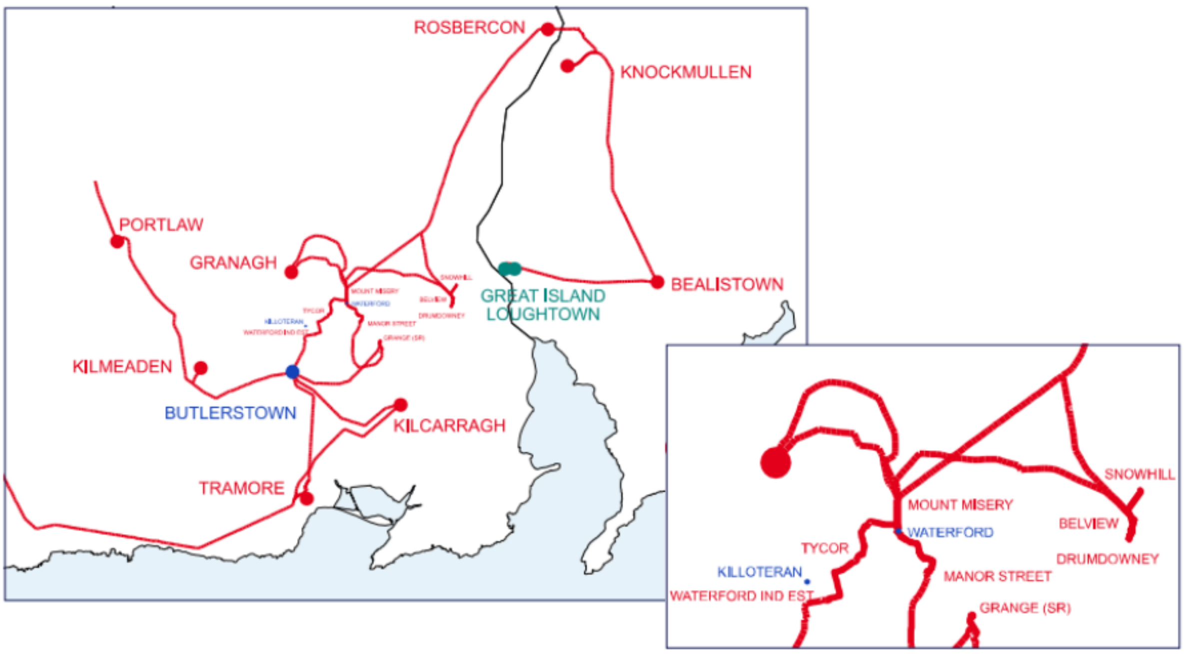


Table 61: Total flexibility needs across Zone 14 for 2028 and 2030

		2028	2030
a	Total Flexibility Need (MW) across zone	0.8 MW	1.3 MW
b	Total Peak Load (MW) across the stations where flexibility needs were identified within the zone	9.34 MW	9.84 MW
c	MW of flexibility need as % of total peak load across the zone (a/b)	8.57%	13.21%

d	Total Flexibility Need (MWh) per zone	5 MWh	36 MWh
e	Total Annual Demand (MWh) across the stations where flexibility needs were identified within the zone	41148.83 MWh	43328.52 MWh
f	MWh of flexibility need as % of total annual demand per zone (d/e)	0.01%	0.08%

In Zone 14, one 38kV/MV station exceeds the non-firm loading limit within the agreed horizon and has been subject to a detailed flexibility needs assessment. A high-level summary of the flexibility needs for this stations is provided in Table 62.

Table 62: Zone 14 Per Station Details

Station Names	MW - 2028/2030	MWh - 2028/2030	Station specific summary
GRANAGH 38 kV/10kV: [2*5MVA]	0.8 MW /1.3 MW	5.0 MWh / 36.0 MWh	As there are no planned reinforcement projects due for completion before 2030, flexibility needs were identified for both target years 2028 and 2030.

Zone 14 is primarily winter driven in its flexibility needs.

7.3.13 Zone 15: Cahir, Ballydine, Doon and Tipperary

Zone 15 is supplied from four 110kV Bulk Supply points at Cahir, Ballydine, Doon and Tipperary, and thirteen 38kV distribution substations as shown in Figure 58.

Figure 58: Zone 15 110kV and 38kV Distribution Network

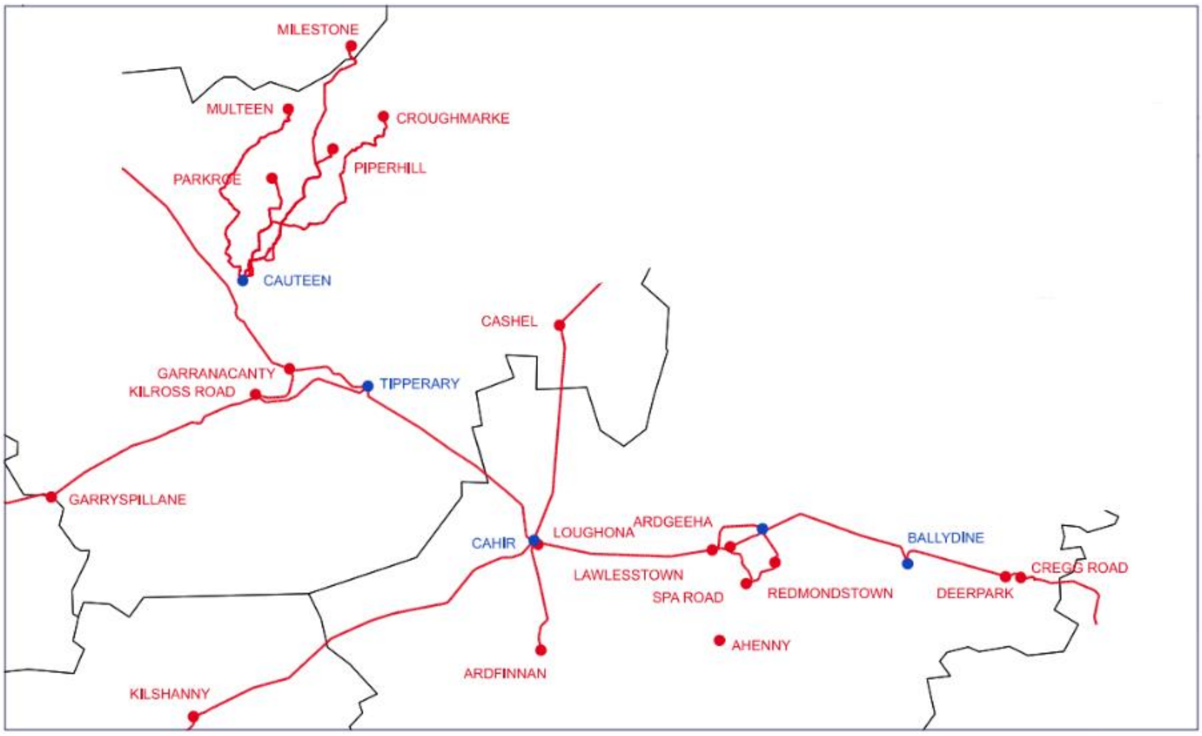


Table 63: Total flexibility needs across Zone 15 for 2028 and 2030

		2028	2030
a	Total Flexibility Need (MW) across zone	2.1 MW	3.44 MW
b	Total Peak Load (MW) across the stations where flexibility needs were identified within the zone	6.38 MW	24.65 MW
c	MW of flexibility need as % of total peak load across the zone (a/b)	32.92%	13.96%
d	Total Flexibility Need (MWh) per zone	328 MWh	558.16 MWh
e	Total Annual Demand (MWh) across the stations where flexibility needs were identified within the zone	24574.61 MWh	119258.61 MWh

f	MWh of flexibility need as % of total annual demand per zone (d/e)	1.33%	0.47%

In Zone 15, two 38kV/MV stations exceed their non-firm loading limits within the agreed horizon and have been subject to detailed flexibility needs assessment. A high-level summary of the flexibility needs for these stations is provided in Table 64.

Table 64: Zone 15 Per Station Details

Station Names	MW - 2028/2030	MWh - 2028/2030	Station specific summary
GARRANACANTY 38 kV/20kV: [2*10MVA]	- / 0.94 MW	/ 1.16 MWh	No flexibility needs were identified in 2028. Additionally, no reinforcement projects are planned.
GARRYSPILLANE 38 kV/10kV: [1*5MVA]	2.1 MW / 2.5 MW	328.0 MWh / 557.0 MWh	As there are no planned reinforcement projects due for completion before 2030, flexibility needs were identified for both target years 2028 and 2030. Additionally, the congestion persists for more than five hours at this station for 2028 and 2030, indicating that flexibility alone may not be a viable long-term solution.

Zone 15 is primarily winter driven in its flexibility needs, also with a need in April.

7.3.14 Zone 16: Thurles, Ikerrin and Nenagh

Zone 16 is supplied from three 110kV Bulk Supply points at Thurles, Ikerrin and Nenagh, and nine 38kV distribution substations as shown in Figure 59.

Figure 59: Zone 16 110kV and 38kV Distribution Network

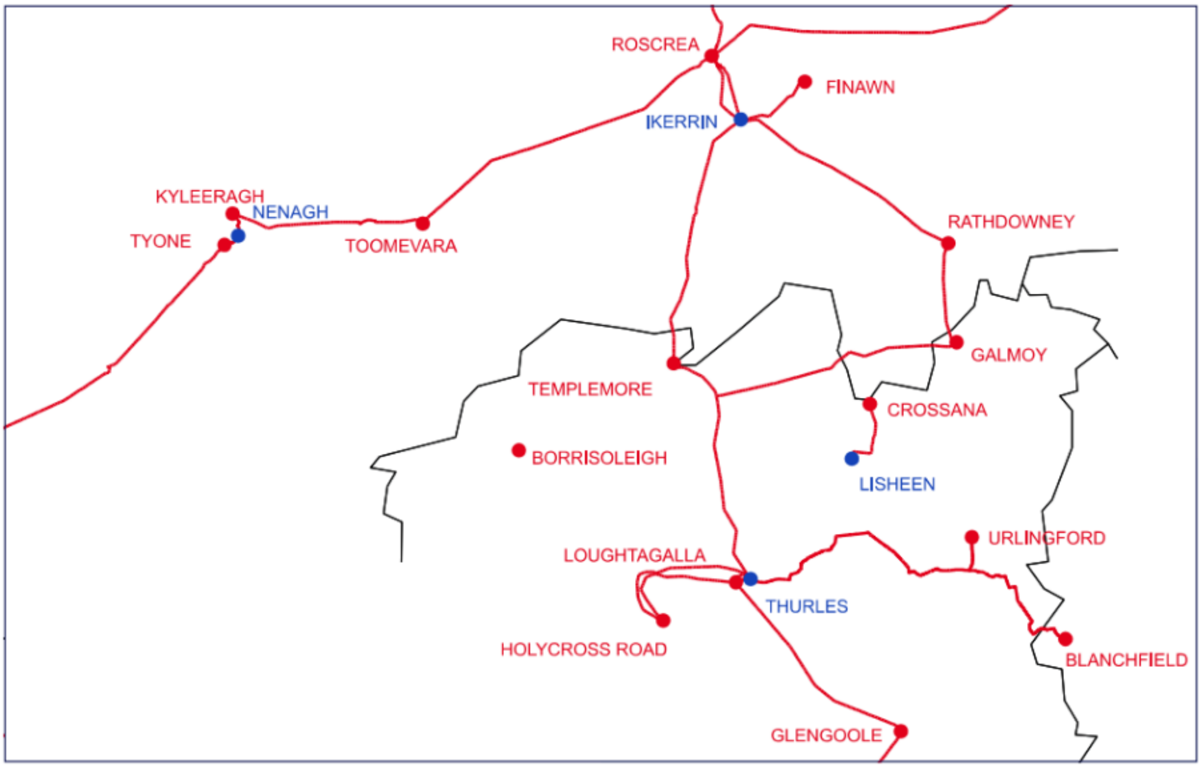


Table 65: Total flexibility needs across Zone 16 for 2028 and 2030

		2028	2030
a	Total Flexibility Need (MW) across zone	32.8 MW	43.48 MW
b	Total Peak Load (MW) across the stations where flexibility needs were identified within the zone	83.42 MW	173.65 MW
c	MW of flexibility need as % of total peak load across the zone (a/b)	39.32%	25.04%
d	Total Flexibility Need (MWh) per zone	2184.5 MWh	5262.94 MWh
e	Total Annual Demand (MWh) across the stations where flexibility needs were identified within the zone	393280.52 MWh	509014.82 MWh

f	MWh of flexibility need as % of total annual demand per zone (d/e)	0.56%	1.03%

In Zone 16, two 110kV/38kV and four 38kV/MV stations exceed their non-firm loading limits within the agreed horizon and have been subject to a detailed flexibility needs assessment. A high-level summary of the flexibility needs for these stations is provided in Table 66.

Table 66: Zone 16 Per Station Details

Station Names	MW - 2028/2030	MWh - 2028/2030	Station specific summary
IKERRIN 110kV/38kV: [1*31.5MVA][50]	7.8 MW / 9.78 MW	881.0 MWh / 2035.64 MWh	As there are no planned reinforcement projects due for completion before 2030, flexibility needs were identified for both target years 2028 and 2030. Additionally, the congestion persists for more than five hours at these stations for 2028 and 2030, indicating that flexibility alone may not be a viable long-term solution.
KYLEERAGH 38kV/10kV: [1*10MVA & 1*5MVA]	0.6 MW / 1.5 MW	4.0 MWh / 72.0 MWh	
NENAGH 110kV/38kV: [1*31.5MVA] [51]	7.9 MW / 10.0 MW	205.0 MWh / 530.0 MWh	
RATHDOWNEY 38kV/10kV: [1*5MVA]	0.5 MW / 0.8 MW	4.0 MWh / 20.0 MWh	As there are no planned reinforcement

[50] Flexibility needs listed for this station are the net need assuming that the flexibility from the downstream stations Rathdowney 38kV/10kV and Roscrea 38kV/10kV are procured and activated.
[51] Flexibility needs listed for this station are the net need assuming that the flexibility from the downstream stations Kyleeragh 38kV/10kV and Toomevara 38kV/10kV are procured and activated.

TOOMEVARA 38kV /10kV [1*5MVA]	0.27 MW / 0.55 MW	0.47 MWh / 2.27 MWh	projects due for completion before 2030, flexibility needs were identified for both target years 2028 and 2030.
ROSCREA 38 kV/10kV: [2*10MVA]	- / 1.0 MW	- / 5.0 MWh	No flexibility needs were identified in 2028 Additionally, no reinforcement projects are planned.

Zone 16 exhibits flexibility needs that are primarily winter-driven, with distinct seasonal variations across stations. Additionally, at Ikerrin 110 kV/38 kV, flexibility needs remain winter-focused up to 2028, transitioning to a full year need thereafter as network conditions evolve.

7.3.15 Zone 17: Ardnacrusha and Limerick

Zone 17 is supplied from four 110kV Bulk Supply points at Ardnacrusha, Singland, Ahane and Limerick, and fifteen 38kV distribution substations as shown in Figure 60.

Figure 60: Zone 17 110kV and 38kV Distribution Network

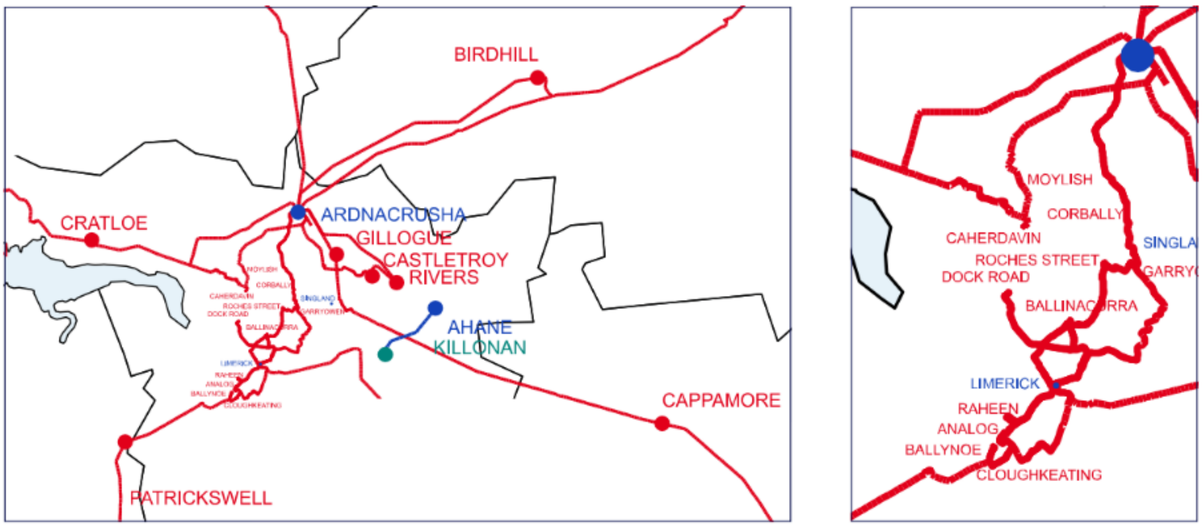


Table 67: Total flexibility needs across Zone 17 for 2028 and 2030

		2028	2030

a	Total Flexibility Need (MW) across zone	3.5 MW	4.89 MW
b	Total Peak Load (MW) across the stations where flexibility needs were identified within the zone	20.57 MW	30.5 MW
c	MW of flexibility need as % of total peak load across the zone (a/b)	17.02%	16.03%
d	Total Flexibility Need (MWh) per zone	186 MWh	285.13 MWh
e	Total Annual Demand (MWh) across the stations where flexibility needs were identified within the zone	77542.84 MWh	115372.77 MWh
f	MWh of flexibility need as % of total annual demand per zone (d/e)	0.24%	0.25%

In Zone 17, three 38kV/MV stations exceed their non-firm loading limits within the agreed horizon and have been subject to detailed flexibility needs assessment. A high-level summary of the flexibility needs for these stations is provided in Table 68.

Table 68: Zone 17 Per Station Details

Station Names	MW - 2028/2030	MWh - 2028/2030	Station specific summary
BRUFF 38kV/10kV: [1*5MVA][52]	1.0 MW / 1.3 MW	4.0 MWh / 9.0 MWh	Flexibility needs are listed only for 2028 as a reinforcement project is planned for completion by 2030. Additionally, the congestion persists for more than five hours at these stations for 2028 and 2030, indicating that
BRUFF 38kV/20kV: [1*5MVA][51]	2.1 MW / 2.5 MW	181.0 MWh / 268.0 MWh	

[52] This station comprises of two transformers operating at distinct medium-voltage levels, 10kV and 20kV. Consequently, the assessment was conducted separately for each transformer, treating them as independent, standalone units.

			flexibility alone may not be a viable long-term solution.
CAPPAMORE 38kV/10kV: [2*5MVA]	- / 0.19 MW	- / 0.13 MWh	No flexibility needs were identified in 2028. Additionally, no reinforcement projects are planned.
CASTLETROY 38kV/10kV: [2*5MVA]	0.4 MW / 0.9 MW	1.0 MWh / 8.0 MWh	As there are no planned reinforcement projects due for completion before 2030, flexibility needs were identified for both target years 2028 and 2030.

Stations in Zone 17 each identified flexibility needs for a single month, distributed across the winter period.

7.3.16 Zone 19: Knockearagh, Tralee and Oughtragh

Zone 19 is supplied from three 110kV Bulk Supply points at Knockearagh, Oughtragh, and Tralee, and fifteen 38kV distribution substations as shown in Figure 61.

Figure 61: Zone 19 110kV and 38kV Distribution Network

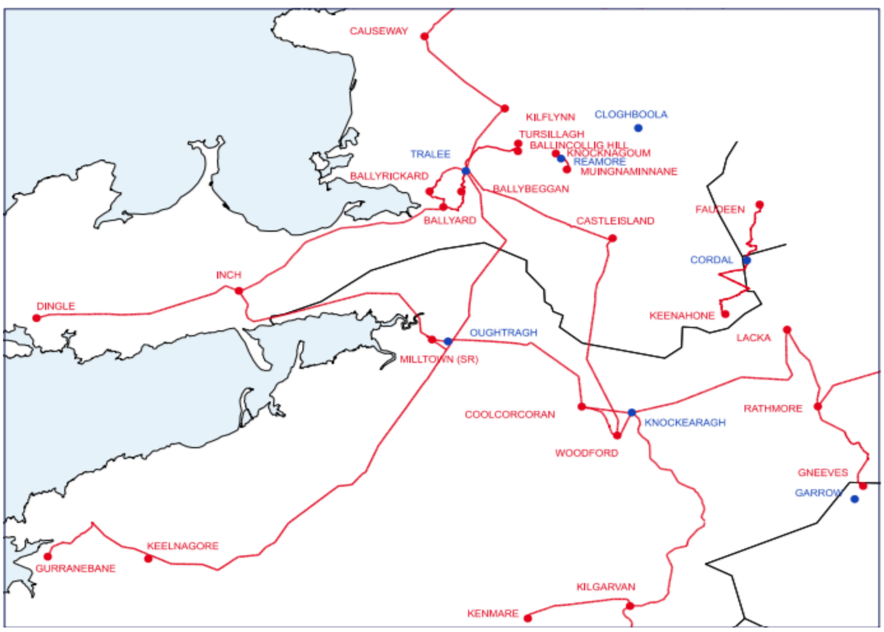


Table 69: Total flexibility needs across Zone 19 for 2028 and 2030

		2028	2030
a	Total Flexibility Need (MW) across zone	2.9 MW	2.8 MW
b	Total Peak Load (MW) across the stations where flexibility needs were identified within the zone	20.01 MW	11.31 MW
c	MW of flexibility need as % of total peak load across the zone (a/b)	14.49%	24.76%
d	Total Flexibility Need (MWh) per zone	170 MWh	348 MWh
e	Total Annual Demand (MWh) across the stations where flexibility needs were identified within the zone	88645.53 MWh	44861.28 MWh
f	MWh of flexibility need as % of total annual demand per zone (d/e)	0.19%	0.78%

In Zone 19, two 38kV/MV stations exceed their non-firm loading limits within the agreed horizon and have been subject to a detailed flexibility needs assessment. A high-level summary of the flexibility needs for these stations is provided in Table 70.

Table 70: Zone 19 Per Station Details

Station Names	MW - 2028/2030	MWh - 2028/2030	Station specific summary
GURRANEBANE 38kV/20kV: [2*5MVA]	0.7 MW / -	7.0 MWh / -	Flexibility needs are listed only for 2028 as a reinforcement project is planned for completion by 2030.
CASTLEISLAND 38kV/10kV: [2*5MVA]	2.20 MW / 2.80 MW	163.0 MWh / 348.0 MWh	As there are no planned reinforcement projects due for completion before 2030, flexibility needs were identified for both target years 2028 and 2030.

			Additionally, the congestion persists for more than five hours at this station for 2028 and 2030, indicating that flexibility alone may not be a viable long-term solution.

Zone 19 shows a predominantly winter-driven flexibility need for the months of January, February, March and November.

7.3.17 Zone 20: Charleville, Mallow and Glenlara

Zone 20 is supplied from three 110kV Bulk Supply points at Charleville, Mallow and Glenlara, and ten 38kV distribution substations as shown in Figure 62.

Figure 62: Zone 20 110kV and 38kV Distribution Network

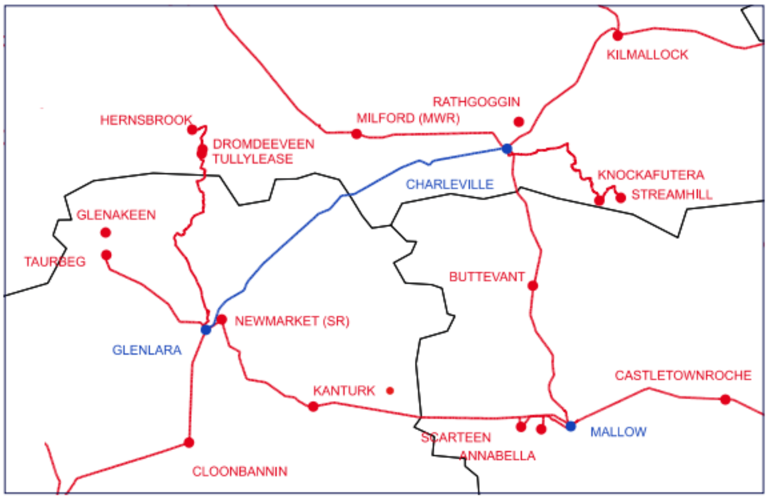


Table 71: Total flexibility needs across Zone 20 for 2028 and 2030

		2028	2030
a	Total Flexibility Need (MW) across zone	0.9 MW	1.54 MW
b	Total Peak Load (MW) across the stations where flexibility needs were identified within the zone	9.41 MW	10.09 MW
c	MW of flexibility need as % of total peak load across the zone (a/b)	9.57%	15.27%

d	Total Flexibility Need (MWh) per zone	23 MWh	138.64 MWh
e	Total Annual Demand (MWh) across the stations where flexibility needs were identified within the zone	49036.84 MWh	52575.79 MWh
f	MWh of flexibility need as % of total annual demand per zone (d/e)	0.05%	0.26%

In Zone 20, only one 38kV/MV station exceeds its non-firm loading limits within the agreed horizon and has been subject to a detailed flexibility needs assessment. A high-level summary of the flexibility needs for this station is provided in Table 72.

Table 72: Zone 20 Per Station Details

Station Names	MW - 2028/2030	MWh - 2028/2030	Station specific summary
SCARTEEN 38kV/10kV: [2*5MVA]	0.90 MW / 1.54 MW	23.0 MWh / 138.64 MWh	As there are no planned reinforcement projects due for completion before 2030, flexibility needs were identified for both target years 2028 and 2030. Additionally, the congestion persists for more than five hours at this station for 2030, indicating that flexibility alone may not be a viable long-term solution.

Zone 20 shows a predominantly winter driven flexibility need for the months of October and November.

7.3.18 Zone 21: Ballylickey and Dunmanway

Zone 21 is supplied from two 110kV Bulk Supply points at Ballylickey and Dunmanway, and nine 38kV distribution substations as shown in Figure 63.

Figure 63: Zone 21 110kV and 38kV Distribution Network

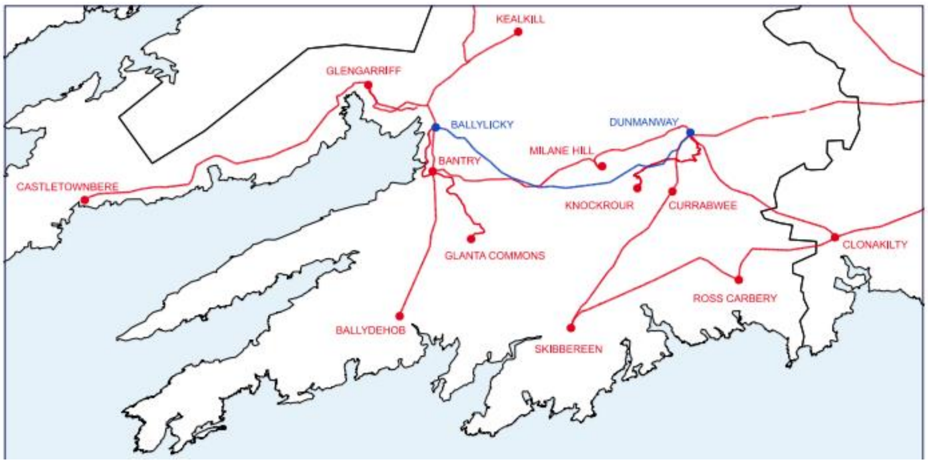


Table 73: Total flexibility needs across Zone 21 for 2028 and 2030

		2028	2030
a	Total Flexibility Need (MW) across zone	1.2 MW	2.2 MW
b	Total Peak Load (MW) across the stations where flexibility needs were identified within the zone	5.48 MW	15.02 MW
c	MW of flexibility need as % of total peak load across the zone (a/b)	21.88%	14.65%
d	Total Flexibility Need (MWh) per zone	29 MWh	74 MWh
e	Total Annual Demand (MWh) across the stations where flexibility needs were identified within the zone	21301.97 MWh	62041.31 MWh
f	MWh of flexibility need as % of total annual demand per zone (d/e)	0.14%	0.12%

In Zone 21, two 38kV/MV stations exceed their non-firm loading limits within the agreed horizon and have been subject to a detailed flexibility needs assessment. A high-level summary of the flexibility needs for these stations is provided in Table 74.

Table 74: Zone 21 Per Station Details

Station Names	MW - 2028/2030	MWh - 2028/2030	Station specific summary
BALLYDEHOB 38kV/20kV: [1*5MVA]	1.20 MW / 1.60 MW	29.0 MWh / 72.0 MWh	As there are no planned reinforcement projects due for completion before 2030, flexibility needs were identified for both target years 2028 and 2030. Additionally, the congestion persists for more than five hours at this station for 2030, indicating that flexibility alone may not be a viable long-term solution.
BANTRY 38kV/10kV: [2*5MVA]	- / 0.60 MW	- / 2.0 MWh	No flexibility needs were identified in 2028. Additionally, no reinforcement projects are planned.

Zone 21 shows flexibility needs predominantly for the month of April with a need in December also identified for of Bantry 38/MV.

7.3.19 Zone 22: Bandon, Macroom and Hartnetts Cross

Zone 22 is supplied from three 110kV Bulk Supply points at Bandon (110kV/38kV and 110kV/MV), Macroom and Hartnetts Cross, and a six 38kV distribution substations as shown in Figure 64.

Figure 64: Zone 22 110kV and 38kV Distribution Network

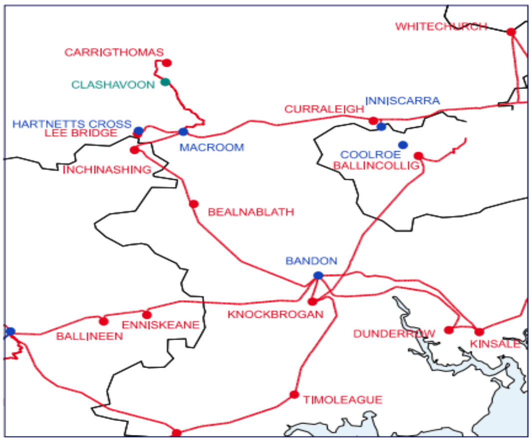


Table 75: Total flexibility needs across Zone 22 for 2028 and 2030

		2028	2030
a	Total Flexibility Need (MW) across zone	3.5 MW	4.7 MW
b	Total Peak Load (MW) across the stations where flexibility needs were identified within the zone	16.34 MW	17.54 MW
c	MW of flexibility need as % of total peak load across the zone (a/b)	21.42%	26.80%
d	Total Flexibility Need (MWh) per zone	220 MWh	477.43 MWh
e	Total Annual Demand (MWh) across the stations where flexibility needs were identified within the zone	56526.25 MWh	60685.38 MWh
f	MWh of flexibility need as % of total annual demand per zone (d/e)	0.39%	0.01%

In Zone 22, two 38kV/MV stations exceed their non-firm loading limits within the agreed horizon and have been subject to a detailed flexibility needs assessment. A high-level summary of the flexibility needs for these stations is provided in Table 76.

Table 76: Zone 22 Per Station Details

Station Names	MW - 2028/2030	MWh - 2028/2030	Station specific summary
BEALNABLATH 38kV/20kV: [1*10MVA]	2.10 MW / 2.90 MW	10.0 MWh / 34.43 MWh	As there are no planned reinforcement projects due for completion before 2030, flexibility needs were identified for both target years 2028 and 2030. Additionally, the congestion persists for more than five hours at these stations for 2030, indicating that flexibility alone may not be a viable long-term solution.
TIMOLEAGUE 38kV/10kV: [1*5MVA]	1.40 MW / 1.80 MW	210.0 MWh / 443.0 MWh	

Zone 22 shows predominantly flexibility needs for winter months i.e. January, March, November and December.

7.3.20 Zone 23: Cork

Zone 23 is supplied from eight 110kV Bulk Supply points at Barnahely (110kV/38kV and 110kV/MV), Cow Cross (110kV/38kV and 110kV/MV), Kilbarry (110kV/38kV and 110kV/MV), Castleview, Coolroe, Marina, Liberty Street and Trabeg (110kV/38kV and 110kV/MV) and a sixteen 38kV distribution substations as shown in Figure 65.

Figure 65: Zone 23 110kV and 38kV Distribution Network

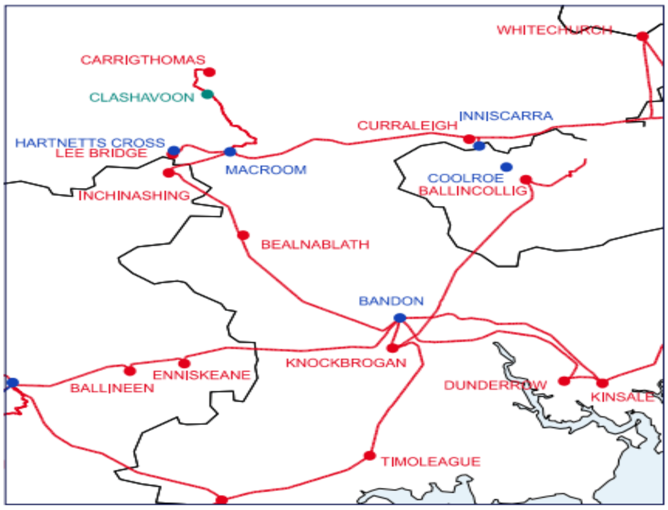


Table 77: Total flexibility needs across Zone 23 for 2028 and 2030

		2028	2030
a	Total Flexibility Need (MW) across zone	2.7 MW	0
b	Total Peak Load (MW) across the stations where flexibility needs were identified within the zone	19.75 MW	0
c	MW of flexibility need as % of total peak load across the zone (a/b)	13.67%	-
d	Total Flexibility Need (MWh) per zone	51 MWh	0
e	Total Annual Demand (MWh) across the stations where flexibility needs were identified within the zone	83333.34 MWh	0
f	MWh of flexibility need as % of total annual demand per zone (d/e)	0.06%	-

In Zone 23, two 38kV/MV stations exceed their non-firm loading limits within the agreed horizon and have been subject to a detailed flexibility needs assessment. A high-level summary of the flexibility needs for these stations is provided in Table 78.

Table 78: Zone 23 Per Station Details

Station Names	MW - 2028/2030	MWh - 2028/2030	Station specific summary
CURRALEIGH 38kV/20kV: [2*5MVA]	1.50 MW / -	35.0 MWh / -	Flexibility needs are listed only for 2028 as a reinforcement project is planned for completion by 2030.
RIVERSTOWN 38kV/10kV: [2*5MVA]	1.20 MW / -	16.0 MWh / -	

Zone 23 shows predominantly flexibility needs for winter months i.e. January, February, March, November and December.

7.3.21 Zone 24: Galway, Salthill and Screebe

Zone 24 is supplied from three 110kV Bulk Supply points at Galway (110kV/38kV and 110kV/MV), Salthill (110kV/38kV and 110kV/MV) and Screeb, and fourteen 38kV distribution substations as shown in Figure 66.

Figure 66: Zone 24 110kV and 38kV Distribution Network

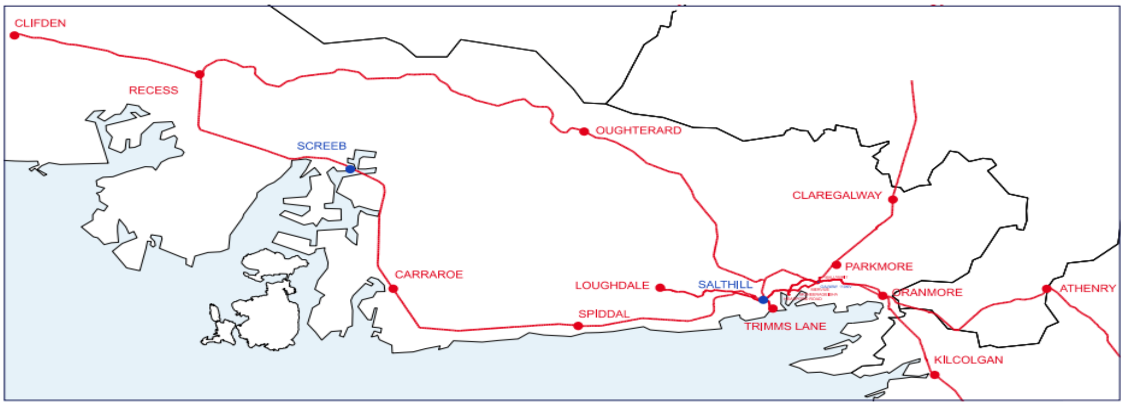


Table 79: Total flexibility needs across Zone 24 for 2028 and 2030

		2028	2030
a	Total Flexibility Need (MW) across zone	2.7 MW	3.4 MW

b	Total Peak Load (MW) across the stations where flexibility needs were identified within the zone	6.93 MW	11.98 MW
c	MW of flexibility need as % of total peak load across the zone (a/b)	38.98%	28.39%
d	Total Flexibility Need (MWh) per zone	508 MWh	852.6 MWh
e	Total Annual Demand (MWh) across the stations where flexibility needs were identified within the zone	26381.03 MWh	46278.23 MWh
f	MWh of flexibility need as % of total annual demand per zone (d/e)	1.93%	1.84%

In Zone 24, two 38kV/MV stations exceed their non-firm loading limits within the agreed horizon and have been subject to a detailed flexibility needs assessment. A high-level summary of the flexibility needs for these stations is provided in Table 80.

Table 80: Zone 24 Per Station Details

Station Names	MW - 2028/2030	MWh - 2028/2030	Station specific summary
KILCOLGAN 38kV/MV: [1*5MVA-38/20kV] [53]	2.70MW / 3.10 MW	508 MWh / 851.0 MWh	As there are no planned reinforcement projects due for completion before 2030, flexibility needs were identified for both target years 2028 and 2030. Additionally, the congestion persists for more than five hours at this station for 2028

[53] This station comprises of two transformers operating at distinct medium-voltage levels, 10kV and 20kV. Consequently, the assessment was conducted separately for each transformer, treating them as independent, standalone units. There is no overloading on the transformer operating on MV voltage of 10kV.

			and 2030, indicating that flexibility alone may not be a viable long-term solution.
CARRAROE 38 kV/10kV: [1*5MVA]:	- / 0.30 MW	- / 1.60 MWh	No flexibility needs were identified in 2028. Additionally, no reinforcement projects are planned.

Zone 24 is primarily winter driven in its flexibility needs for the months December, January and February.

7.3.22 Zone 25: Barrymore, Midleton and Dungarvan

Zone 25 is supplied from three 110kV Bulk Supply points at Barrymore, Midleton (110kV/38kV and 110kV/MV) and Dungarvan, and fourteen 38kV distribution substations as shown in Figure 67.

Figure 67: Zone 25 110kV and 38kV Distribution Network

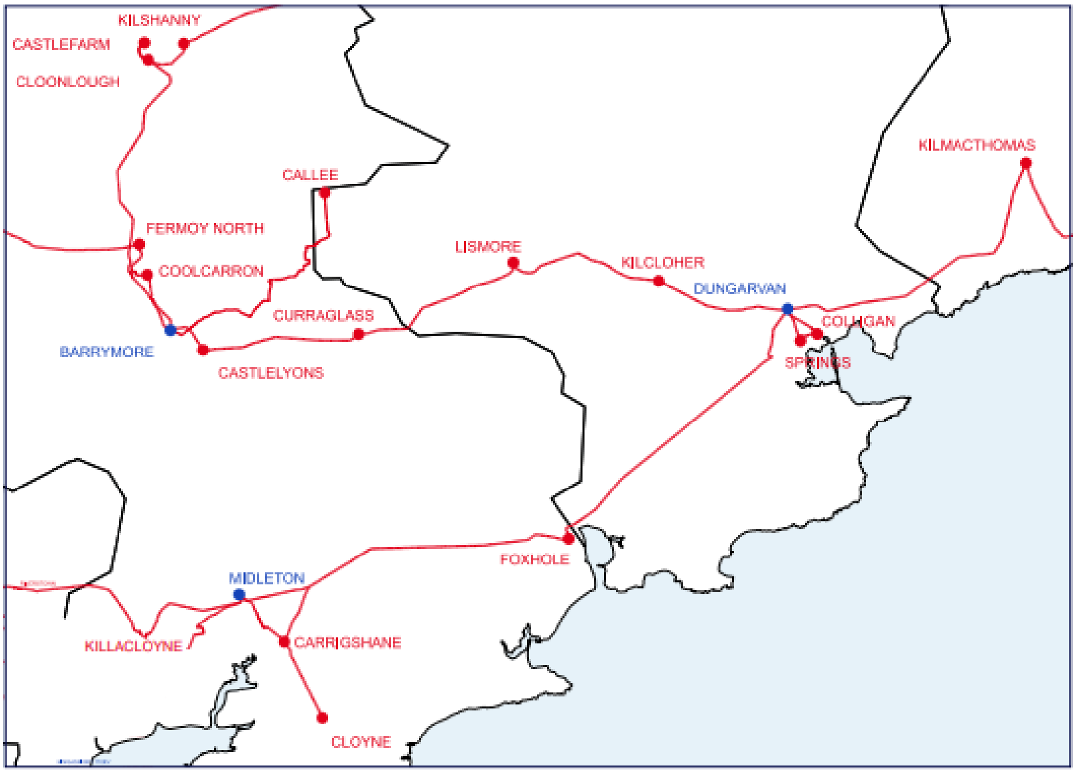


Table 81: Total flexibility needs across Zone 25 for 2028 and 2030

		2028	2030
a	Total Flexibility Need (MW) across zone	22.6 MW	1.86 MW
b	Total Peak Load (MW) across the stations where flexibility needs were identified within the zone	92.34 MW	23.2 MW
c	MW of flexibility need as % of total peak load across the zone (a/b)	24.47%	8.02%
d	Total Flexibility Need (MWh) per zone	17698 MWh	83.11 MWh
e	Total Annual Demand (MWh) across the stations where flexibility needs were identified within the zone	508628.00 MWh	95090.74 MWh
f	MWh of flexibility need as % of total annual demand per zone (d/e)	3.48%	0.09%

Since there are multiple reinforcement projects scheduled for this zone, most occurring between 2028 and 2030 and resulting in a significant reduction in flexibility needs in 2030 compared with 2028 (as it is expected that the projects will address the station congestion).

In Zone 25, six 38kV/MV stations and one 110kV/38kV station exceed their non-firm loading limits within the agreed horizon and have been subject to a detailed flexibility needs assessment. A high-level summary of the flexibility needs for these stations is provided in Table 82.

Table 82: Zone 25 Per Station Details

Station Names	MW - 2028/2030	MWh - 2028/2030	Station specific summary
MIDLETON 110kV/38kV: [1*31.5MVA][54]	6.6 MW / -	3032.0 MWh / -	Flexibility needs are listed only for 2028 as a reinforcement project is
CLOYNE 38kV/10kV: [1*5MVA]	0.9 MW / -	10.0 MWh / -	

[54] Flexibility needs listed for this station are the net need assuming that the flexibility from the downstream stations Cloyne 38kV/10kV and Killacloyne 38kV/10kV are procured and activated.

KILLACLOYNE38kV/10kV [2*5MVA] [55]	3.4 MW / -	6650.0 MWh / -	planned for completion by 2030. Additionally, the congestion persists for more than five hours at these stations for 2028 and 2030, indicating that flexibility alone may not be a viable long-term solution.
KILLACLOYNE 38kV/10kV [1*5MVA][54]	4.5 MW / -	2280.0 MWh / -	
COOLCARRON 38kV/10kV: [1*5MVA]	2.0 MW / -	857.0 MWh / -	
FERMOY NORTH 38kV/10kV: [2*5MVA]	3.9MW / -	4825.0 MWh / -	
KILCLOHER 38kV/10kV: [1*5MVA]	1.3 MW / 1.7MW	44.0 MWh / 83.0 MWh	As there are no planned reinforcement projects due for completion before 2030, flexibility needs were identified for both target years 2028 and 2030. Additionally, the congestion persists for more than five hours at this station for 2030, indicating that flexibility alone may not be a viable long-term solution.
FOXHOLE 38kV/20kV: [2*10MVA]	- / 0.16 MW	- / 0.11 MWh	No flexibility needs were identified for 2028 therefore only 2030 needs are reported.

Zone 25 is primarily winter driven in its flexibility needs, except for Killacloyne 38 kV/MV, which shows the highest MW/MWh flexibility need within the zone and requires flexibility across the full year.

[55] This station has 2 separate 10kV busbars. The transformer capacity's feeding into each busbar therefore assessed and reported separately.

7.3.23 Zone 26: Ennis, Tullabrack and Drumline

Zone 26 is supplied from three 110kV Bulk Supply points at Ennis (110kV/38kV and 110kV/MV) Tullabrack and Drumline, and fourteen 38kV distribution substations as shown in Figure 68.

Figure 68: Zone 26 110kV and 38kV Distribution Network

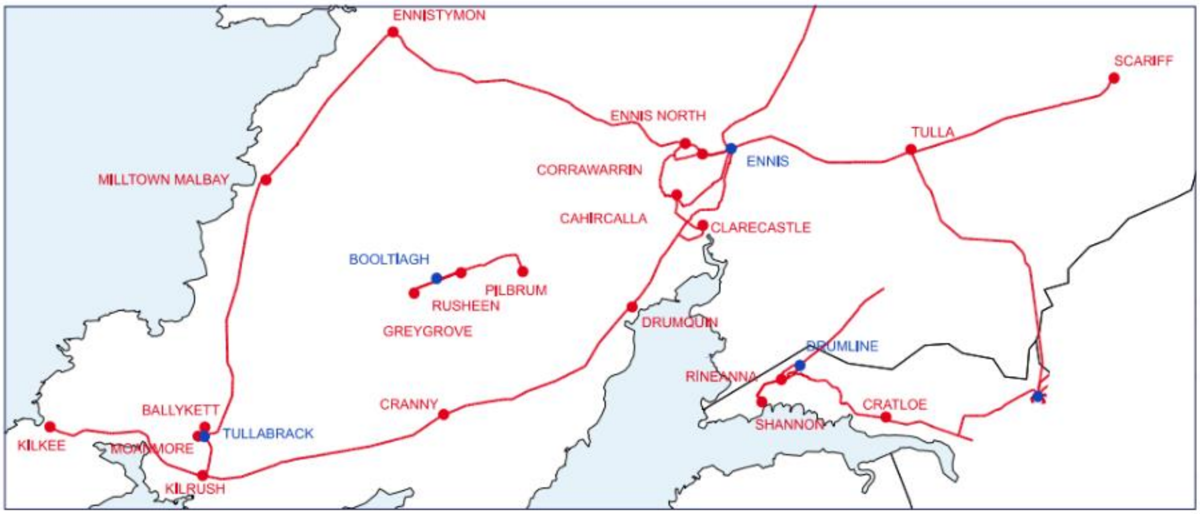


Table 83: Total flexibility needs across Zone 26 for 2028 and 2030

		2028	2030
a	Total Flexibility Need (MW) across zone	4.7 MW	3.6 MW
b	Total Peak Load (MW) across the stations where flexibility needs were identified within the zone	34.58 MW	16.39 MW
c	MW of flexibility need as % of total peak load across the zone (a/b)	13.59%	21.96%
d	Total Flexibility Need (MWh) per zone	139 MWh	155 MWh
e	Total Annual Demand (MWh) across the stations where flexibility needs were identified within the zone	159950.31 MWh	68998.36 MWh
f	MWh of flexibility need as % of total annual demand per zone (d/e)	0.09%	0.22%

In Zone 26[56], four 38kV/MV stations exceed their non-firm loading limits within the agreed horizon and have been subject to a detailed flexibility needs assessment. A high-level summary of the flexibility needs for these stations is provided in Table 84.

Table 84: Zone 26 Per Station Details

Station Names	MW - 2028/2030	MWh - 2028/2030	Station specific summary
CAHIRCALLA 38kV/10kV: [2*5MVA]	1.9 MW / 2.6 MW	44.0 MWh / 135.0 MWh	As there are no planned reinforcement projects due for completion before 2030, flexibility needs were identified for both target years 2028 and 2030. Additionally, the congestion persists for more than five hours at this station for 2030, indicating that flexibility alone may not be a viable long-term solution.
SCARIFF 38kV/10kV: [1*5MVA]	0.7 MW / 1.0 MW	4.0 MWh / 20.0 MWh	As there are no planned reinforcement projects due for completion before 2030, flexibility needs were identified for both target years 2028 and 2030.
ENNISTYMON 38kV/10kV: [2*5MVA]	1.6 MW / -	89.0 MWh / -	Flexibility needs are listed only for 2028 as a reinforcement project is planned for completion by 2030.
ENNIS NORTH 38kV/10kV: [2*5MVA]	0.5 MW / -	2.0 MWh / -	

[56] There is one non-SCADAfied station (Drumquin 38kV/10kV) within Zone 26, therefore no flexibility need assessment has been performed for this station.

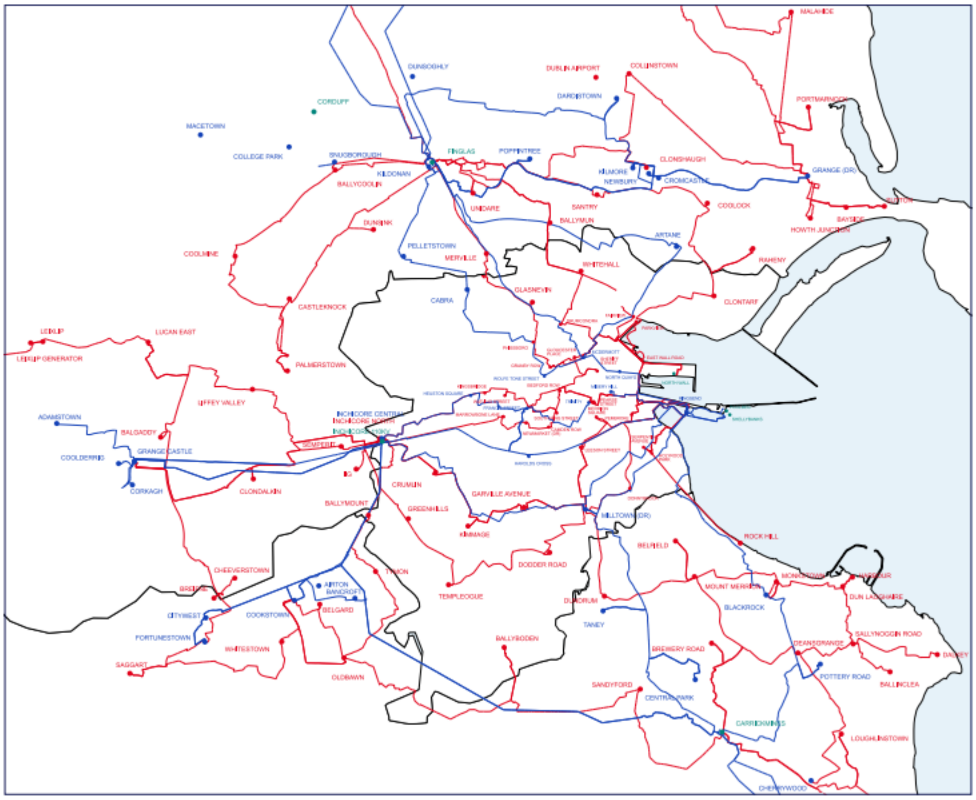
Zone 26 is primarily winter driven in its flexibility needs.

7.3.24 Zone 27: Greater Dublin Area

The distribution system in the Greater Dublin Area is supplied at 220kV, 110kV, 38kV, medium voltage (10kV and 20kV), and low voltage network. ESB Networks has divided the Greater Dublin Area into three Planner Groups: Central, North, and South.

Zone 27 is supplied from a total of nine Bulk Supply Points (where the higher voltage B/B is under the control of the Transmission System Operator (EirGrid). Four of these are 220kV - at Finglas, Ringsend, Carrickmines and Inchicore. The remaining five are 110kV at Baltrasna, College Park, Corduff, Griffinrath, and Macetown as shown in Figure 69.

Figure 69: Zone Greater Dublin HV Distribution Network



As the greater Dublin area is very large in size, for the purpose of reporting the flexibility needs assessment details, Dublin South, Dublin North and Dublin Central are dealt with separately.

Zone 27: Dublin South

Table 85: Total flexibility needs across Zone 27 (Dublin South) for 2028 and 2030

		2028	2030
a	Total Flexibility Need (MW) across zone	10.6 MW	18.2 MW
b	Total Peak Load (MW) across the stations where flexibility needs were identified within the zone	78.85 MW	139.29 MW
c	MW of flexibility need as % of total peak load across the zone (a/b)	13.44%	13.12%
d	Total Flexibility Need (MWh) per zone	683 MWh	1862.7 MWh
e	Total Annual Demand (MWh) across the stations where flexibility needs were identified within the zone	343771.35 MWh	615654.46 MWh
f	MWh of flexibility need as % of total annual demand per zone (d/e)	0.20%	0.30%

In Zone 27 Dublin South, seven 38kV/MV stations exceed their non-firm loading limits within the agreed horizon and have been subject to a detailed flexibility needs assessment. A high-level summary of the flexibility needs for these stations is provided in Table 86.

Table 86: Zone 27 (Dublin South) Per Station Details

Station Names	MW - 2028/2030	MWh - 2028/2030	Station specific summary
BALLYBODEN-38kV/10kV: [2*10MVA]	1.80 MW / 3.30 MW	9.0 MWh / 107.0 MWh	As there are no planned reinforcement projects due for completion before 2030, flexibility needs were identified for both target years 2028 and 2030.
GREY STONES 38kV/10kV: [2*10MVA]	1.90 MW / 3.40 MW	15.0 MWh / 131.0 MWh	
LOUGHLINSTOWN-38kV/10kV: [2*10MVA]	2.10 MW / 3.30 MW	83.0 MWh / 284.0 MWh	

BRAY-38kV/10kV: [2*10MVA	- / 1.35 MW	- / 2.63 MWh	No flexibility needs were identified in 2028. Additionally, no reinforcement projects are planned.
CARRICKMINES-38kV/10kV: [1*10MVA & 1*15MVA]	- /0.086 MW	-/0.043 MWh	
SANDYFORD-38kV/10kV: [2*10MVA]	- /0.72 MW	-/1.79 MWh	
LITTLE BRAY-38kV/10kV: [2*10MVA]	4.70 MW / 6.12 MW	576.0 MWh / 1336.32 MWh	As there are no planned reinforcement projects due for completion before 2030, flexibility needs were identified for both target years 2028 and 2030. Additionally, the congestion persists for more than five hours at this station for 2028 and 2030, indicating that flexibility alone may not be a viable long-term solution.

Zone 27 Dublin South is primarily winter driven in its flexibility needs. However, there is a need in May, June, July and August for Little Bray 38 kV/MV.

Zone 27: Dublin North

Table 87: Total flexibility needs across Zone 27 (Dublin North) for 2028 and 2030

		2028	2030
a	Total Flexibility Need (MW) across zone	42.47 MW	53.8 MW
b	Total Peak Load (MW) across the stations where flexibility needs were identified within the zone	273.11 MW	250.47 MW
c	MW of flexibility need as % of total peak load across the zone (a/b)	15.55%	21.48%

d	Total Flexibility Need (MWh) per zone	10238.09 MWh	17277 MWh
e	Total Annual Demand (MWh) across the stations where flexibility needs were identified within the zone	1276433.62 MWh	1168880.18 MWh
f	MWh of flexibility need as % of total annual demand per zone (d/e)	0.80%	1.48%

In Zone 27 Dublin North thirteen 38kV/MV stations and one 110/MV station exceed their non-firm loading limits within the agreed horizon and have been subject to a detailed flexibility needs assessment. A high-level summary of the flexibility needs for these stations is provided in Table 88.

Table 88: Zone 27 (Dublin North) Per Station Details

Station Names	MW - 2028/2030	MWh - 2028/2030	Station specific summary
BALLYCOOLIN-38kV/10kV: [3*10MVA]	3.10 MW / 5.70 MW	262.0 MWh / 1640.0 MWh	As there are no planned reinforcement projects due for completion before 2030, flexibility needs were identified for both target years 2028 and 2030. Additionally, the congestion persists for more than five hours at these stations for 2028 and 2030, indicating that flexibility alone may not be a viable long-term solution.
CELBRIDGE-38kV/10kV: [2*10MVA]	3.90 MW / 5.90 MW	122.0 MWh / 441.0 MWh	
LEIXLIP-38kV/10kV: [2*10MVA]	1.70 MW / 3.50 MW	25.0 MWh / 180.0 MWh	
LUCAN EAST-38kV/10kV: [2*5MVA]	2.10 MW / 3.0 MW	149.0 MWh / 563.0 MWh	
POPPINTREE-110kV/10kV: [2*20MVA]	17.40 MW / 20.0 MW	8966.0 MWh / 13460.0 MWh	

SAGGART-38kV/10kV: [2*5MVA]	1.70 MW / 2.50 MW	46.0 MWh / 157.0 MWh	
SEMPERIT-38kV/10kV: [3*10MVA]	0.50 MW / 2.90 MW	1.0 MWh / 147.0 MWh	
MALAHIDE-38kV/10kV: [2*10MVA	3.40 MW / 5.30 MW	120.0 MWh / 516.0 MWh	
SALLINS-38kV/10kV: [2*10MVA]	-/1.20 MW	- / 10.0 MWh	No flexibility needs were identified in 2028 Additionally, no reinforcement projects are planned.
CLONTARF 38kV/10kV: [1*10MVA]	1.30 MW / 2.10 MW	25.0 MWh / 144.0 MWh	As there are no planned reinforcement projects due for completion before 2030, flexibility needs were identified for both target years 2028 and 2030.
GRANGE (DR)-38kV/10kV: [2*10MVA]	0.15 MW / 1.70 MW	0.08 MWh / 19.0 MWh	
COOLMINE-38kV/10kV: [2*10MVA]	5.40 MW /-	503.0 MWh /-	Flexibility needs are listed only for 2028 as a reinforcement project is planned for completion by 2030. Additionally, the congestion persists for more than five hours at these stations for 2028, indicating that flexibility alone may not be a viable long-term solution.
KILCOCK-38kV/20kV: [2*10MVA]	1.80 MW /-	19.0 MWh /-	Flexibility needs are listed only for 2028 as a

LOUGHSHINNY-38kV/10kV: [2*10MVA]	0.02 MW / -	0.01 MWh / -	reinforcement project is planned for completion by 2030.

Zone 27 Dublin North[57] is primarily winter driven in its flexibility needs.

Zone 27: Dublin Central

Table 89: Total flexibility needs across Zone 27 (Dublin Central) for 2028 and 2030

		2028	2030
a	Total Flexibility Need (MW) across zone	18.6 MW	18.3 MW
b	Total Peak Load (MW) across the stations where flexibility needs were identified within the zone	116.94 MW	86.59 MW
c	MW of flexibility need as % of total peak load across the zone (a/b)	15.91%	21.13%
d	Total Flexibility Need (MWh) per zone	2375.91 MWh	3583 MWh
e	Total Annual Demand (MWh) across the stations where flexibility needs were identified within the zone	530811.73 MWh	379078.18 MWh
f	MWh of flexibility need as % of total annual demand per zone (d/e)	0.45%	0.95%

A total of eight 38kV stations in Zone 27 Dublin Central exceed their non-firm loading limits within the agreed horizon and have been subject to a detailed flexibility needs assessment. A high-level summary of the flexibility needs for these stations is provided in Table 90.

Table 90: Zone 27 (Dublin Central) Per Station Details

Station Names	MW - 2028/2030	MWh - 2028/2030	Station specific summary

[57] Dublin North has the highest flexibility needs across the country in 2030.

CAMDEN ROW 38kV/10kV: [1*15 MVA][58]	- / 0.5 MW	- / 2.0 MWh	No flexibility needs were identified in 2028. Additionally, no reinforcement projects are planned.
CLONDALKIN 38kV/10kV: [3*10 MVA]	1.0 MW / -	0.91 MWh / -	Flexibility needs are listed only for 2028 as a reinforcement project is planned for completion by 2030.
DONNYBROOK 38kV/10kV: [2*10 MVA]	5.1 MW / -	460.0 MWh / -	Flexibility needs are listed only for 2028 as a reinforcement project is planned for completion by 2030. Additionally, the congestion persists for more than five hours at this station indicating that flexibility alone may not be a viable long-term solution.
FAIRVIEW 38kV/10kV: [1*15 MVA]	4.1 MW / 5.3 MW	650.0 MWh / 1290.0 MWh	As there are no planned reinforcement projects due for completion before 2030, flexibility needs were identified for both target years 2028 and 2030.
GLASNEVIN 38kV/10kV: [1*10 MVA]	4.7 MW / 5.8 MW	1218.0 MWh / 2034.0 MWh	

[58] Due to substantial data gaps (zero/negligible readings) in the 2024 historical SCADA dataset, the detailed assessment was completed using the full 2025 SCADA data for this station.

NEWMARKET (DR) 38kV/10kV: [1*10 MVA]	1.0 MW / 1.8 MW	16.0 MWh / 105.0 MWh	Additionally, the congestion persists for more than five hours at these stations for 2028 and 2030, indicating that flexibility alone may not be a viable long-term solution.
WHITEHALL 38kV/10kV: [1*10 MVA]	1.1 MW / 1.9 MW	14.0 MWh / 43.0 MWh	
KIMMAGE 38kV/10kV: [2*10 MVA]	1.5 MW / 3.1 MW	17.0 MWh / 109.0 MWh	As there are no planned reinforcement projects due for completion before 2030, flexibility needs were identified for both target years 2028 and 2030.

Zone 27 Dublin Central is primarily winter driven in its flexibility needs.

7.4 Downward flexibility findings

In line with the methodology document, downward flexibility was assessed under two approaches:

1) Impact due to flexible generation: Downward flexibility due to the need to constrain flexible generation was estimated as 1.38MWh in 2025. No significant increase is expected in 2028 and 2030.

2) Impact due to micro-/mini-generation: downward flexibility due to the need to constraint flexible generation was estimated as shown in the table below:

Table 91: Potential Downward Flexibility Needs due to microgeneration

Year	MW flex	MWh flex
2025	1.19	643
2028	2.26	1223
2030	3.77	2035

7.5 Distribution network flexibility needs key messages

The distribution level analysis identifies localised flexibility needs associated with forecast station overloads and network congestion due to demand. The total requirement is modest in system-wide energy terms but is materially concentrated in specific zones and stations. The Dublin flexibility need is particularly notable, with Dublin North, Central and South accounting for a significant proportion of the identified requirement by 2030.

The results also show that identified needs are location-specific and sensitive to planned reinforcement, with some needs reducing where reinforcement is expected to address station congestion. This indicates that distribution flexibility is likely to be most relevant as a targeted tool for managing localised constraints, including through targeted procurement and short-term flexibility products or markets where these can address needs ahead of, or alongside, network reinforcement.

The assessment also identified potential wider local network benefits from flexibility, including positive impacts on voltage in the case assessed. The assessment of downward flexibility found that current expected constraints associated with flexible generation connections and microgeneration are relatively limited at present, although these areas are expected to continue evolving as the distribution system changes.

Part C: Options to meet identified flexibility needs

This part of the report considers the potential of non-fossil flexibility resources such as demand response and energy storage, including aggregation and interconnection, to fulfil the identified flexibility needs, at both the system and network level.

8. Options to reduce RES dispatch down

This section of the report looks at the potential impact of additional flexible resources on reduction of RES dispatch down and therefore helping to meet RES integration needs. This analysis has been completed by EirGrid in line with Articles 16(6), 8(10), 8(11), 8(12), 1(6) and 16(11) of the ACER Methodology.

The ACER Methodology requires that the TSO considers a technology neutral approach to analysing the benefit of adding flexible resources. This is done through considering generalised representations of a number of characteristics relevant to flexibility such as power, energy capacity, energy-to-power ratio, availability, and round trip efficiency, rather than considering characteristics relevant to particular types of flexible resource. Therefore, this analysis also does not pre-determine or present results to give a conclusion on the type of flexibility which would be best suited to meet the relevant flexibility needs. If particular types of flexible resource, such as shorter duration battery storage, LDES technologies, flexible demand, etc. can meet the relevant characteristics studied, then the results for the scenarios with those characteristics can be taken to give insight on the potential impact for those technologies.

8.1 Impact of additional flexible resources on reduction of RES dispatch down

The following scenarios were analysed to explore the potential impact of additional flexible resources on reduction of RES dispatch down.

Table 92: Various scenarios to explore the potential impact of additional flexible resources on reduction of RES dispatch down - Article 16(6)

Scenario	Year	Power, MW (IE)	Energy, MWh (IE)	Power, MW (NI)	Energy, MWh (NI)
Base/High RES	2030	1,510	3,162	241	222
SDF additional to Base/High RES	2030	1,510	3,162	241	222
LDF 8hr additional to Base/High RES	2030	1,510	12,078	241	1929

LDF 20hr additional to Base/High RES	2030	1,510	30,196	241	4822

These scenarios consider the impact of doubling the available power to import in MW against what is in the base case in the model, and for that added flexible capacity considering different potential durations of response in MWh terms, firstly using the same duration as what is in the base case in the model (Short Duration Flexibility, SDF), then increasing the duration to 8hrs (Long Duration Flexibility 8hr, LDF 8hr). In one study these two scenarios were combined, where both the shorter duration and longer duration additional flexibility capacities were added to the model, to give an indication of the impact of additional capacity with mixed durations. For a subset of years and scenarios an additional study was run where the duration of the flexibility was increased to 20hrs (LDF 20hr), to give an indication of the impact of additional duration.

It should be noted that these capabilities were added to the FNA model and the results below reflect their impact on the System Flexibility Needs (surplus and curtailment). Since the network model is not included in the FNA model it is not possible to determine the impact on the transmission network flexibility needs (constraints). Therefore, while constraint results are included for completeness for the total dispatch down figure, focus should be given to the impact on surplus + curtailment results. It should also be noted that the flexible capacity was doubled in both Ireland and Northen Ireland, given the all-island nature of the wholesale electricity market, but the following results focus on the impact of this on Ireland alone, given the scope of the national FNA report.

Below results are given in terms of the annual dispatch down figures in percentage terms, as the main metric of focus for EirGrid in analysing impacts on RES dispatch down, but also the average hourly dispatch down figures in percentage terms and one of the main metrics of focus in the FNA methodology. Also, the results are given for the base case and for the High RES scenario for completeness, but as outlined in Section 5.4 it is advised to focus on the results for the High-RES scenario.

Table 93: Annual and average hourly dispatch down (%) for base vs various flexibility and high-RES scenarios, 2028, WS4 – Article 16(6)

WS4, 2028, IE	Base	SDF	LDF 8hr	SDF & LDF 8hr	High RES	SDF High RES	LDF 8hr High RES	SDF & LDF 8hr High RES
Annual Surplus + Curtailment Dispatch Down, %	2.33%	1.89%	0.91%	0.76%	7.01%	6.55%	4.80%	4.42%
Annual ECP Constraint Dispatch Down, %	9.84%	9.84%	9.84%	9.84%	10.82%	10.82%	10.82%	10.82%
Annual Total Dispatch Down, %	**12.17%**	**11.73%**	**10.75%**	**10.60%**	**17.83%**	**17.37%**	**15.62%**	**15.24%**
Average Hourly Surplus + Curtailment Dispatch Down, %	0.95%	0.76%	0.35%	0.29%	3.07%	2.85%	2.04%	1.87%
Average Hourly ECP Constraint Dispatch Down, %	8.94%	8.94%	8.94%	8.94%	9.66%	9.66%	9.66%	9.66%
Average Hourly Total Dispatch Down, %	**9.88%**	**9.69%**	**9.28%**	**9.22%**	**12.74%**	**12.51%**	**11.71%**	**11.53%**

Table 94: Annual and average hourly dispatch down (%) for base vs various flexibility and high-RES scenarios, 2030, WS4 – Article 16(6)

WS4, 2030, IE	Base	SDF	LDF 8hr	SDF & LDF 8hr	High RES	SDF High RES	LDF 8hr High RES	SDF & LDF 8hr High RES
Annual Surplus + Curtailment Dispatch Down, %	7.27%	6.49%	4.54%	4.10%	22.47%	21.94%	20.11%	19.57%
Annual ECP Constraint Dispatch Down, %	6.05%	6.05%	6.05%	6.05%	7.10%	7.10%	7.10%	7.10%
Annual Total Dispatch Down, %	**13.32%**	**12.54%**	**10.59%**	**10.15%**	**29.57%**	**29.04%**	**27.21%**	**26.67%**
Average Hourly Surplus + Curtailment Dispatch Down, %	3.34%	2.95%	2.02%	1.81%	11.95%	11.58%	10.48%	10.14%
Average Hourly ECP Constraint Dispatch Down, %	5.09%	5.09%	5.09%	5.09%	6.23%	6.23%	6.23%	6.23%
Average Hourly Total Dispatch Down, %	**8.42%**	**8.02%**	**7.10%**	**6.89%**	**18.16%**	**17.78%**	**16.69%**	**16.35%**

Table 95: Annual and average hourly dispatch down (%) for base vs various flexibility and high-RES scenarios, 2028, WS34 – Article 16(6)

WS34, 2028, IE	**Base**	**SDF**	**LDF 8hr**	**SDF & LDF 8hr**	**High RES**	**SDF High RES**	**LDF 8hr High RES**	**SDF & LDF 8hr High RES**
Annual Surplus + Curtailment Dispatch Down, %	1.89%	1.54%	0.82%	0.67%	6.74%	6.19%	4.58%	4.24%
Annual ECP Constraint Dispatch Down, %	9.84%	9.84%	9.84%	9.84%	10.82%	10.82%	10.82%	10.82%
Annual Total Dispatch Down, %	**11.73%**	**11.38%**	**10.66%**	**10.51%**	**17.56%**	**17.01%**	**15.40%**	**15.06%**
Average Hourly Surplus + Curtailment Dispatch Down, %	0.77%	0.62%	0.33%	0.27%	3.05%	2.78%	2.00%	1.84%
Average Hourly ECP Constraint Dispatch Down, %	8.94%	8.94%	8.94%	8.94%	9.66%	9.66%	9.66%	9.66%
Average Hourly Total Dispatch Down, %	**9.69%**	**9.55%**	**9.26%**	**9.20%**	**12.67%**	**12.40%**	**11.63%**	**11.48%**

Table 96: Annual and average hourly dispatch down (%) for base vs various flexibility and high-RES scenarios, 2030, WS34 – Article 16(6)

WS34, 2030, IE	**Base**	**SDF**	**LDF 8hr**	**SDF & LDF 8hr**	**High RES**	**SDF High RES**	**LDF 8hr High RES**	**SDF & LDF 8hr High RES**
Annual Surplus + Curtailment Dispatch Down, %	7.65%	6.89%	5.24%	4.85%	23.62%	23.11%	21.44%	21.00%
Annual ECP Constraint Dispatch Down, %	6.05%	6.05%	6.05%	6.05%	7.10%	7.10%	7.10%	7.10%
Annual Total Dispatch Down, %	**13.70%**	**12.94%**	**11.29%**	**10.90%**	**30.72%**	**30.21%**	**28.54%**	**28.10%**
Average Hourly Surplus + Curtailment Dispatch Down, %	3.67%	3.26%	2.43%	2.25%	12.83%	12.44%	11.38%	11.10%
Average Hourly ECP Constraint Dispatch Down, %	5.09%	5.09%	5.09%	5.09%	6.23%	6.23%	6.23%	6.23%
Average Hourly Total Dispatch Down, %	**8.75%**	**8.34%**	**7.51%**	**7.33%**	**19.04%**	**18.65%**	**17.60%**	**17.32%**

Table 97: Annual and average hourly dispatch down (%) for base vs various flexibility and high-RES scenarios, 2028, WS28 – Article 16(6)

WS28, 2028, IE	Base	SDF	LDF 8hr	SDF & LDF 8hr	High RES	SDF High RES	LDF 8hr High RES	SDF & LDF 8hr High RES
Annual Surplus + Curtailment Dispatch Down, %	1.84%	1.41%	0.47%	0.40%	6.36%	5.77%	3.92%	3.59%
Annual ECP Constraint Dispatch Down, %	9.84%	9.84%	9.84%	9.84%	10.82%	10.82%	10.82%	10.82%
Annual Total Dispatch Down, %	**11.68%**	**11.25%**	**10.31%**	**10.24%**	**17.18%**	**16.58%**	**14.74%**	**14.40%**
Average Hourly Surplus + Curtailment Dispatch Down, %	0.78%	0.59%	0.19%	0.16%	2.89%	2.60%	1.71%	1.55%
Average Hourly ECP Constraint Dispatch Down, %	8.94%	8.94%	8.94%	8.94%	9.66%	9.66%	9.66%	9.66%
Average Hourly Total Dispatch Down, %	**9.72%**	**9.52%**	**9.12%**	**9.09%**	**12.56%**	**12.26%**	**11.38%**	**11.21%**

Table 98: Annual and average hourly dispatch down (%) for base vs various flexibility and high-RES scenarios, 2030, WS28 – Article 16(6)

WS28, 2030, IE	Base	SDF	LDF 8hr	SDF & LDF 8hr	High RES	SDF High RES	LDF 8hr High RES	SDF & LDF 8hr High RES
Annual Surplus + Curtailment Dispatch Down, %	7.26%	6.33%	4.51%	4.09%	23.00%	22.41%	20.74%	20.28%
Annual ECP Constraint Dispatch Down, %	6.05%	6.05%	6.05%	6.05%	7.10%	7.10%	7.10%	7.10%
Annual Total Dispatch Down, %	**13.31%**	**12.38%**	**10.56%**	**10.14%**	**30.10%**	**29.51%**	**27.84%**	**27.38%**
Average Hourly Surplus + Curtailment Dispatch Down, %	3.54%	3.01%	2.12%	1.91%	12.56%	12.12%	11.10%	10.80%
Average Hourly ECP Constraint Dispatch Down, %	5.09%	5.09%	5.09%	5.09%	6.23%	6.23%	6.23%	6.23%
Average Hourly Total Dispatch Down, %	**8.61%**	**8.09%**	**7.20%**	**6.99%**	**18.77%**	**18.34%**	**17.31%**	**17.01%**

Focusing on the main representative scenario considered (WS28 2030 High RES) and including a brief set of additional analysis which was carried out with longer duration flexibility, the following are a subset of the results to give an indication of the potential impact, both in annual dispatch down percentage terms and in annual dispatch down energy (GWh) terms.

Table 99: Results for annual total dispatch down (%), Annual Surplus + Curtailment Dispatch Down, GWh, 2030, WS28 – Article 16(6)

WS28, 2030, IE, High RES	High RES	SDF High RES	LDF 8hr High RES	SDF&LDF High RES	LDF 20hr High RES
Annual Surplus + Curtailment Dispatch Down, %	23.00%	22.41%	20.74%	20.28%	18.74%
Annual ECP Constraint Dispatch Down, %	7.10%	7.10%	7.10%	7.10%	7.10%
Annual Total Dispatch Down, %	**30.10%**	**29.51%**	**27.84%**	**27.38%**	**25.84%**
Annual Surplus + Curtailment Dispatch Down, GWh	**9,852.14**	**9,599.40**	**8,884.28**	**8,689.35**	**8,026.70**
Savings GWh Dispatch achieved compared High-RES case	**0**	**252.74**	**967.86**	**1162.79**	**1825.44**

These results show that 1,510MW of 20-hour long duration flexibility in the High RES scenario saves 4.26% dispatch down, which amounts to 1,825 GWh. The results suggest that dispatch down reduces further when longer duration flexibility capabilities are added. This provides reason to believe that while higher power capacity of flexible resources would be beneficial, longer duration flexibility would be further beneficial, in particular if it were possible to have flexibility without any energy limits.

The following results are provided to focus on the relative impact differentiated between surplus and curtailment.

Table 100: Relative impact between surplus and curtailment

WS28, 2030, IE, High RES	High RES	SDF High RES	LDF 8hr High RES	SDF&LDF High RES	LDF 20hr High RES
Annual Surplus Dispatch Down, %	18.54%	17.57%	15.69%	15.13%	13.81%
Annual Curtailment Dispatch Down, %	4.46%	4.84%	5.05%	5.15%	4.93%
Annual ECP Constraint Dispatch Down, %	7.10%	7.10%	7.10%	7.10%	7.10%

Annual Total Dispatch Down, %	**30.10%**	**29.51%**	**27.84%**	**27.38%**	**25.84%**

These results clearly show that the main impact of additional flexibility is to help reduce RES dispatch down driven by surplus. If there is surplus RES availability above the level of demand and exports available to utilise that available energy, then by having additional capacity to flexibly increase consumption from the system can lead to a direct reduction in the level of RES dispatch down due to this surplus.

The limitations of flexible resources to reduce dispatch down is largely a function of how the dispatch down arises, and in particular how long continuous durations of dispatch down can only be partly solved by relatively shorter duration flexibility resources. Some of these characteristics can be seen in the results outlined in 3.1.1.7 and it should be noted that these results are only for the base case – it would be expected that the durations of the blocks, and the MW and MWh sizes of the blocks, would be even greater in the High RES scenario.

For instance, with long continuous blocks of large MWh amounts of dispatch down over multiple hours and potentially even days, if energy limited flexible resources required to consume power to reduce the dispatch down, if they quickly reach their energy limits (e.g. short duration storage) then a very large capacity of such flexibility would be necessary to be able to continuously absorb energy to reduce dispatch down. Additionally these resources, once at their energy limits, would be restricted from exporting until the dispatch down event has concluded, further limiting their value and economic efficiency to overall system outcomes.

The table below outlines some additional results considering the blocky characteristics of the RES dispatch down for what would be required to consider the potential for additional flexibility with similar features to completely eradicate dispatch down due to surplus curtailment, taking results from Section 5.1.5 on the peak dispatch down level, maximum continuous duration of dispatch down, and similar results for the High RES scenario.

Table 101: Results for the additional scenarios to consider the potential for additional flexibility, 2030, WS28 – Article 16(6)

Scenario	Peak Surplus + Curtailment DD, MW	Largest block of surplus + curtailment DD, hours	Largest block average surplus + curtailment DD, MW	MW of 4-hour flexibility required to supply largest block.	MW of 20-hour flexibility required to supply largest block.	Hours of flexibility at peak MW required to supply largest block.
WS28 2030	7,455	70	2,303	40,303	8,061	22
WS28 2030 High RES	11,163	156	4,526	176,514	35,303	63

In these results the calculation for the level of capacity of each flexibility response duration required to eradicate all dispatch down is based on a simple calculation of dividing the number of hours in the largest block by the duration of the response being considered, and multiplying this result by the average dispatch down in that block. An example of the results from this simple high-level analysis shows that the flexibility capacity which would be required to eradicate the longest block of surplus + curtailment dispatch down is 177 GW of 4-hour duration flexibility in the WS28 2030 High-RES scenario. Based on this high-level analysis, it would be difficult to develop sufficient levels of flexibility with these features to completely eradicate dispatch down in the timeframes considered.

This also highlights the potential value of adding flexibility which has no energy limited / unlimited duration of response. Simplified post-processing analysis was carried out on the same WS28 2030 High-RES scenario to consider the potential level of surplus + curtailment dispatch down that could be reduced if the same additional capacity of flexibility (1510MW) was added which has no energy limit. This was done by considering these resources being able to turn on at a variable MW level whenever there was surplus + curtailment such that they could reduce dispatch down to the minimum of the level in that period or the maximum MW capacity of that additional capability. From this analysis using the High-RES scenario, it was found that the value for surplus + curtailment could be:

- 2.1% in 2028 (compared with 7.26% without any additional flexible capacity), and;
- 12.9% in 2030 (compared with 23% without any additional flexible capacity).

8.2 Interdependency analysis

A series of sensitivity analyses were carried out, focusing on the WS28 2030 base scenario, to investigate the impact and interdependencies of the main drivers for RES dispatch down in the results. The FNA model was rerun with different combinations of the drivers removed to compare with the base case results to determine the relative impacts on surplus and curtailment. The base case ECP results for the RES constraint impact were determined by comparing models with and without the network model, and therefore for the transmission impact aspect of this consideration they can just be considered entirely included or excluded from the results. This analysis was completed in line with Article 16(10).

Table 102: Results for the Surplus + Curtailment, Transmission Constraint and Total Dispatch Down, %, for various scenarios, 2030, WS28 – Article 16(10)

Scenario	Surplus + Curtailment Dispatch Down, %	Transmission Constraint Dispatch Down, %	Total Dispatch Down, %
Base	7.26	6.05	13.31
No Short Term Needs incorporated	7.12	6.05	13.17
No Ramping Needs incorporated	7.16	6.05	13.21
No Ramping Needs or Short	7.03	6.05	13.08

Term Needs Incorporated			
No Operational Constraints	4.37	6.05	10.42
No Operational Constraints or Short Term Needs incorporated	2.52	6.05	8.57
No Operational Constraints or Ramping Needs incorporated	4.05	6.05	10.1
No Operational Constraints or Ramping Needs or Short Term Needs incorporated	2.57	6.05	8.62
No Transmission Network Constraints	7.26	0	7.26
No Short Term Needs incorporated or Transmission Network Constraints	7.12	0	7.12
No Ramping Needs incorporated or Transmission Network Constraints	7.16	0	7.16
No Ramping Needs or Short Term Needs incorporated or Transmission Network Constraints	7.03	0	7.03
No Operational Constraints or Transmission Network Constraints	4.37	0	4.37
No Operational Constraints or Transmission Network Constraints or Short Term Needs incorporated	2.52	0	2.52
No Operational Constraints or Transmission Network Constraints or Ramping Needs incorporated	4.05	0	4.05
No Operational Constraints or Transmission Network Constraints or Ramping or Short Term Needs incorporated	2.57	0	2.57

Table 103 gives the same results but as the differences to the reference base scenario, with commentary provided on the potential implications of these results.

Table 103: Results for the Differences to Base Scenario with Surplus + Curtailment, Transmission Constraint and Total Dispatch Down, %, for various scenarios, 2030, WS28 – Article 16(10)

	Differences to Base Scenario (positive means Base value is lower)			**Note**
Scenario	**Surplus + Curtailment Dispatch Down, %**	**Transmission Constraint Dispatch Down, %**	**Total Dispatch Down, %**	
No Short Term Needs incorporated	-0.14	0	-0.14	Better wind and solar power and load forecasts alongside generators / BESS which can provide FCR or FRR without requiring being on will reduce the dispatch down. The effect here is minimal.
No Ramping Needs incorporated	-0.1	0	-0.1	Generator flexibility has little effect on dispatch down. Note, this is an hourly simulation running both NI and IE as copper plate models. It's expected that a minutely fully nodal model could result in a high value of better generator flexibility for reducing dispatch down.
No Ramping Needs or Short Term Needs incorporated	-0.23	0	-0.23	-
No Operational Constraints	-2.89	0	-2.89	Removing operational constraints to reduce the system's min-non-VRES-generation level will have a substantial difference to dispatch down.
No Operational Constraints or Short Term Needs incorporated	-4.74	0	-4.74	Removing operational constraints is synergetic with the reduction of wind and solar power and load forecast errors alongside generators / BESS which can provide FCR or FRR without requiring being on. Without operational constraints, the flexibility gains from generators not having to provide short term flexibility is greater.
No Operational Constraints or Ramping Needs incorporated	-3.21	0	-3.21	Removing operational constraints is synergetic with removal of ramping needs represented through generator ramping characteristics, where alternative generators / BESS can help to meet the net

				residual load variations without being on. Without operational constraints, the flexibility gained from removing these ramping characteristics is greater.
No Operational Constraints or Ramping Needs or Short Term Needs incorporated	-4.69	0	-4.69	Same as two points just above.
No Transmission Network Constraints	0	-6.05	-6.05	Improving the transmission system is the largest potential for reducing dispatch down.
No Short Term Needs incorporated or Transmission Network Constraints	-0.14	-6.05	-6.19	-
No Ramping Needs incorporated or Transmission Network Constraints	-0.1	-6.05	-6.15	-
No Ramping Needs or Short Term Needs incorporated or Transmission Network Constraints	-0.23	-6.05	-6.28	-
No Operational Constraints or Transmission Network Constraints	-2.89	-6.05	-8.94	-
No Operational Constraints	-4.74	-6.05	-10.79	-

or Transmission Network Constraints or Short Term Needs incorporated				
No Operational Constraints or Transmission Network Constraints or Ramping Needs incorporated	-3.21	-6.05	-9.26	-
No Operational Constraints or Transmission Network Constraints or Ramping Needs or Short Term Needs incorporated	-4.69	-6.05	-10.74	With all limitations to dispatch down considered removed, the removal of transmission constraints accounts for about three fifths the total reduction in dispatch down. The removal of operational constrains accounts for around one quarter of the total reduction.

8.3 Key messages

The assessment identifies flexibility needs in terms of the power and energy characteristics required by the system (MW and MWh), which may be met by a range of flexibility resources, including demand-side response, storage and other forms of flexibility. Results from this analysis indicate that increased capacity of flexibility resources would reduce RES surplus and curtailment, with longer-duration flexibility delivering the greatest value. The benefit is especially clear in terms of total amount of reduced dispatch down in total energy terms, and the benefit seems to come primarily from reducing the impact of RES dispatch down due to renewable surplus. Dispatch down of renewable energy is more pronounced in regions where high levels of renewable energy are being integrated onto power systems, such as Ireland.

Increasing capacity of shorter duration flexibility appears to lead to somewhat more diminishing returns than increasing the duration of the flexibility. Some of this appears to be due to the “blocky” nature of RES dispatch down events, with long continuous duration and high MWh level of dispatch down. This could also indicate that although both shorter and longer duration flexibility is needed to meet different needs, the need for longer duration flexibility is greater to minimise RES dispatch down. There may be more value in exploring flexibility approaches which have even longer durations to those considered in this analysis, or potentially those flexible resources which do not have duration or energy limits.

However, regardless of the value of such increased flexibility capabilities at longer or shorter durations, the levels of capacity of such resources that would be required to completely eradicate RES dispatch down on their own would need to be very large. Therefore, some level of remaining RES dispatch down should be expected, and other means through which RES dispatch down can be further reduced other than the development of additional flexible capabilities should also be progressed. Enhancements and improvements in transmission infrastructure and operational constraints are key drivers for reducing RES dispatch down (Curtailment and Constraints). Making further progress to develop the transmission network in line with EirGrid's Network Development Plan[59], and to implement the actions in EirGrid and SONI's Operational Policy Roadmap[60], will be important in themselves to help directly reduce RES dispatch down, and in doing so would also enable flexible resources to operate in a more effective way to have greater impact in reducing RES dispatch down.

[59] Network Development Plan
[60] Operational Policy Roadmap

9. Options to meet the identified distribution level needs

This section of the report maps distribution-level flexibility needs to potential solutions, with distribution congestion identified as the DSO's primary actionable need.

This analysis has been undertaken by ESB Networks in accordance with Article 16(1) of the ACER Methodology. This section provides a high-level indication of the types of flexibility that may be suitable to address the identified needs.

Specifically, this section covers:

- a high-level linkage between congestion needs and solutions categories, and
- a discussion of locational considerations, realistic delivery timescales of the identified flexibility solutions, and interactions with SEM arrangements.

The scope of this section is limited to distribution-level congestion only (feeder[61] and substation scale). The analysis covers solution types at a high level, including demand response, storage (by duration), flexible generation, interconnection/cross-border options, and digital and operational measures.

9.1 High-level linkage between congestion needs and probable solution categories

This section maps the congestion need (overload during defined hours) to solution categories and explains the rationale.

9.1.1 Flexibility Solution Categories

Table 104 presents the identified solution categories and provides a high-level assessment of their suitability.

[61] It is important to note that in this iteration of the Flexibility Needs Analysis report, flexibility services to address overloads on overhead lines or cables have not been identified

Table 104: High-level assessment of flexibility solution categories

Number	Solution Category	High-level Assessment
1.	Demand Response (DR) Implicit and Explicit	Best fit for short evening peaks and predictable daily windows. Evening peaks are concentrated into a few predictable hours, allowing responses to be pre-scheduled around recurring daily patterns. This provides certainty to Flexibility Service Providers (FSPs) to facilitate planning. **Explicit DR** procured by the DSO provides the highest locational certainty. **Implicit DR (retail tariffs)** can reduce peak growth but is less reliable for firm congestion relief. Where firm, verifiable performance is required explicit DR provides the best option, as its activation and results can be directly tested and confirmed.
2	Storage by Duration	**Short-duration BESS (0.25–4 h)** is highly effective for daily peak congestion and fast response. **Medium-duration storage** can address multi-hour events. **Long-duration/seasonal storage** is generally a **poor fit** for local congestion because locational dispatchability and cost per avoided reinforcement are unfavourable.
3	Dispatchable Local Generation	**Partially suited** where local generation can be dispatched into the congested feeder, but planning, emissions and fuel logistics often limit viability. Best used where existing local generation can be repurposed or where hybrid projects are considered.

4	Flexible Demand Connections	**Well-suited** where customers can tolerate controlled or flexible access to capacity, enabling new load to connect ahead of reinforcement, or existing load to increase their Maximum Import Capacity (MIC). Best applied to large, flexible industrial or commercial loads, EV charging hubs, and data centres willing to operate under agreed pre-determined parameters. **Less suitable** where constraint risk is high, poorly forecastable, or where customer processes require firm, uninterrupted supply.
5	Interconnection and Cross Border Flexibility	**System-scale** solutions that can indirectly reduce distribution congestion by lowering system peaks but are **poor locational matches** for specific feeder overloads and have long lead times. These should be considered as TSO-only measures. It is, however, worth noting that ESB Networks works with the TSO to enable cross participation (e.g. Dynamic Instruction Sets).
6	Digital and Operational Measures	Enablers rather than standalone measures Advanced telemetry, dynamic reconfiguration, and market stacking platforms increase the deliverability and bankability of Demand Response and storage, and can materially shorten lead times and reduce costs

9.1.2 Structured comparison – key decision criteria

The following provides a structured comparison of flexibility solutions and key decision criteria to be used when considering one against the other.

Table 105: Structured comparison of flexibility solutions

Solution	Unit response time	Duration match	Locational fit	Indicative lead time[62]
DSO-Procured Explicit DR	Seconds–minutes	Good for 0.5–4 h peaks	High (feeder/substation)	6–24 months
Implicit DR / Smart Tariffs	Minutes–hours	Variable; weaker for firm events	Medium (area/system)	6–24 months
Dedicated Local Storage (0.25–4 h)	Sub second–seconds	Excellent for daily peaks	Very high (point of connection)	12–36 months
Customer BTM Storage	Seconds–minutes	Good if state of charge managed	Medium (depends on telemetry)	6–24 months
Dispatchable Local Generation	Minutes	Partial (depends on fuel)	Medium–High (if on feeder)	12–48 months
Flexible Demand Connections	Minutes–hours	Good for multi-hour congestion if customer processes allow	High (site-specific, tied to the congested plant)	6–18 months
Interconnection / Cross-Border	Minutes–hours	Poor for specific feeder needs	Low (system scale)	>36 months

[62] Lead times refer to the indicative deployment horizon to implement each flexibility solution — from project initiation or procurement to operational readiness. These are discussed in more detail in section 4.2.3.

Digital / Operational Measures	Seconds–minutes	Enables other solutions	High (enables locational control)	3–18 months
Long-Duration / Seasonal Storage	Hours–days	Poor for short congestion events	Low (system scale)	>60 months

9.1.3 Glossary of solutions (short definitions and key attributes)

The following provides a glossary for the solutions provided in the assessment above.

- **DSO-procured explicit demand response**: contracted reductions or shifts in customer load called directly by the DSO or its agent.
  Key attributes: response seconds–minutes; duration typically 0.5–4 hours; high locational precision (feeder/substation); requires baseline, telemetry and contractual operability tests.
- **Implicit demand response and smart tariffs**: price signals or time-varying tariffs that incentivise customers to change consumption without direct dispatch.
  Key attributes: response minutes–hours; duration variable; area or zone level rather than point-specific; lower contractual certainty for firm congestion relief.
- **Dedicated FTM local storage (BESS 0.25–4 h)**: electrochemical storage sited at or near the congested plant used to inject or absorb power on demand.
  Key attributes: response sub-second–seconds; duration 0.25–4 hours; point-of-connection dispatchability; requires connection, planning and SOC telemetry.
- **Customer BTM storage**: collections of customer assets (stationary batteries, EVs & fleets), typically aggregated by an intermediary to provide a single contracted product.
  Key attributes: response seconds–minutes; duration depends on asset mix; locational fit depends on telemetry and aggregation model; needs clear settlement and visibility rules.
- **Dispatchable local generation**: dispatchable generation located on the distribution network (e.g., gas engines, bioenergy, reciprocating engines) used to relieve local congestion. Hybrids (dynamic sharing of MEC) offers a way to achieve RES dispatchability by combining it with storage.
  Key attributes: response minutes; duration depends on fuel and operational constraints; medium–high locational fit; subject to planning, emissions and fuel availability considerations.
- **Flexible demand connections**: flexible connection agreements that allow new demand to connect ahead of reinforcement by accepting controlled constraint during periods of network congestion.
  Key attributes: response minutes–hours; duration suitable for multi-hour congestion windows where processes can be paused, reduced, or shifted; limited where demand is inflexible or continuous; high locational fit; requires clear constraint rules.

- **Interconnection and cross-border flexibility**: capacity and energy flows across transmission interconnectors that change system-level supply and demand patterns.
  Key attributes: response minutes–hours; duration variable; low locational specificity for feeder congestion; long lead times and system-scale impact.
- **Digital and operational measures**: software, telemetry, market-stacking platforms and network control techniques that improve utilisation of existing assets and enable flexible dispatch.
  Key attributes: response seconds–minutes; enables other solutions to be deliverable; high locational enablement value; lead time depends on metering and IT integration.
- **Long-duration and seasonal storage**: technologies designed to store energy for many hours to months (e.g., pumped hydro, hydrogen, thermal seasonal stores).
  Key attributes: response hours–days; duration >24 hours up to seasonal; poor fit for short, locational congestion but valuable for system-scale seasonal balancing; long development and capital timelines.

9.2 Locational considerations

The following provides a discussion of locational considerations for the flexibility solutions.

- **Proximity to the congested asset:** Solutions must be physically connected to, or controllable at, the specific feeder or substation experiencing overload. The closer the resource is to the congested plant, the higher its electrical effectiveness.
- **Locational dispatchability and controllability:** The DSO must be able to *direct and predictably* activate the resource. Explicit DR and feeder-sited storage score highest; system-wide measures score lowest.
- **Firmness and verifiability of response:** Resources must deliver measurable, testable relief at the exact location during the defined congestion window. This is essential for avoiding thermal or voltage violations.
- **Network topology sensitivity:** Effectiveness depends on how power flows through the local network. Some solutions (e.g., reconfiguration, BESS) can influence flows precisely; others (e.g., cross-border flexibility) have negligible locational impact.

9.3 Delivery timescales and realistic expectations

The following provides a brief discussion of indicative asset delivery timescales for projects to deliver the flexibility solutions. They represent typified estimations of how long it takes for a solution to be planned, approved, installed, and commissioned so it can actively contribute to managing network congestion. For completeness, the timelines do not factor is the impact of work which may still be required to be undertaken by the DSO (for example monitoring and control equipment required to ensure system security.)

These are based on industry experience and project maturity across different flexibility types, with the following time bandings as guides:

- **Shorter lead times (3–18 months)** → operational or digital measures. These rely on existing assets or software upgrades.

- **Medium lead times (6–24 months)** → demand response schemes, customer storage, or smart tariffs. These depend on customer engagement and telemetry setup.
- **Longer lead times (12–48 months)** → physical assets like dedicated storage or local generation, which require engineering design, grid connection, and procurement.
- **Very long lead times (> 36 months)** → interconnection or seasonal storage, reflecting major infrastructure development and regulatory coordination.

Table 106 provides more detail on the elements that go into determining the deployment timeline for each flexibility category.

Table 106: Estimated timeline for delivery of various Flexible Solutions

Solution	Key Pipeline Stages Affecting Lead Time	Observed Timeline Evidence (Typical Range / Milestone)	References
Implicit DR / Smart Tariffs	Tariff design, regulatory approval, customer communication, system changes, enrolment, behavioural adoption.	6–24 months mainly driven by tariff design, approval and rollout.	Retail Energy Code Tariff Interoperability Project (UK).
Dedicated Local Storage (0.25–4 h)	Site selection, feasibility/design, grid connection application, civil works, battery procurement, commissioning.	12–36 months typical; procurement, grid connection, and commissioning are main drivers.	Eurelectric Connection-queue workstream.
Customer BTM Storage	Customer contracting, site works, installation, control integration, SoC management & aggregation qualification.	6–24 months typical (faster for residential – 3-5 months; longer for aggregated commercial portfolios requiring telemetry, grid connection).	Residential - Solar Info Ireland installer timelines; SEAI grant process Commercial – EirGrid DS3 Gate 3 procurement timelines.
Dispatchable Local Generation	Fuel supply arrangements, permitting, plant construction, grid connection.	12–48 months depending on technology and consenting; fuel	Eurelectric connection-queue workstream; Centre on Regulation in Europe report of Flexibility in the

		dependent ramp times noted.	Energy Sector (May 2025).
Flexible Demand Connections	Contracting with large customers, process changes, telemetry & control integration.	6–18 months where customer processes and site controls are not in place; shorter if only contractual/IT changes.	UK Accelerating Electricity Network Connections for Strategic Demand; Eurelectric's from Backlog to Breakthrough: Managing Connection Queues in Distribution Networks.
Interconnection / Cross-Border	Major planning, regulatory approvals, construction, cross TSO coordination.	>36 months (multi year infrastructure projects; strategic planning horizon).	UK Accelerating Electricity Network Connections for Strategic Demand.
Digital / Operational Measures	Software development, platform integration, testing, provider onboarding.	3–18 months for platform upgrades, API rollout and market readiness.	EirGrid DSU comms & testing.
Long-Duration / Seasonal Storage	R&D / project financing, large scale procurement, permitting, grid reinforcements.	>60 months typical for seasonal/large scale projects.	UK Scenario Deployment Analysis for Long-Duration Electricity Storage.

9.4 Interaction with SEM arrangements and revenue stacking

The following section outlines how Flexible Service Providers (FSPs) that are contracted to deliver DSO flexibility services may also participate in existing Single Electricity Market (SEM) arrangements.

The TSO/DSO Operating model framework (agreed between EirGrid and ESB Networks) currently determines how distribution connected flexibility resources can participate across wholesale, balancing, and capacity markets, while simultaneously delivering contracted DSO services. The key challenge is to avoid conflicting obligations and ensure that FSPs can comply with DSO operating envelopes or schedules while also fulfilling their SEM market commitments.

This topic has been the subject of extensive consideration by ESB Networks and EirGrid through development of the TSO-DSO Operating Model detailed design through the Joint

System Operator Programme. That work is ongoing, with the overarching objective of enabling optimal stacking of flexibility services from a whole-of-system perspective. For clarity, the stacking principles are grouped into three broad product types, which collectively encompass all products referenced elsewhere in this document.

9.4.1 Scheduled flexibility products

Scheduled flexibility products are those for which DSO operating envelopes or schedules are provided to the FSP sufficiently in advance to allow the FSP to understand applicable network congestion limits before committing to market positions in the SEM. An example of this is the ESB Networks Demand Flexibility Product, where operating envelopes are shared well in advance of Day-Ahead Market closure. This approach is intended to maximise stacking potential by enabling FSPs to trade in the SEM in a manner that remains within DSO network limits.

For scheduled flexibility products, resources that participate in both DSO services and SEM arrangements remain subject to all obligations entered into under each framework, as well as the associated consequences for non-compliance, regardless of any perceived primacy between obligations. Accordingly, FSPs are expected to ensure that they only enter into combinations of obligations that they can realistically meet.

Providing operating envelopes or schedules ahead of SEM trading deadlines supports informed decision-making by FSPs and enables maximum stacking potential, with the responsibility placed on the FSP to manage its commercial and operational exposure appropriately.

9.4.2 Unscheduled flexibility products

Unscheduled flexibility products are those that may be activated closer to real time and therefore do not provide FSPs with sufficient notice to reflect potential DSO congestion limits in their SEM trading positions.

As a result, stacking potential for unscheduled products is more limited due to the uncertainty around the timing and likelihood of activation. Nevertheless, the underlying principle remains unchanged: FSPs are expected to enter into SEM obligations only where they remain capable of meeting those obligations alongside any existing DSO flexibility commitments.

9.4.3 Flexible demand connections

Customers connected under Flexible Demand Connection arrangements may also participate in SEM wholesale, balancing, and capacity markets, subject to compliance with the operating limits defined in their connection agreements. Further work is required between ESB Networks and EirGrid as part of the operating model detailed design with respect to Flexible Demand Connections. The overarching principle remains that the obligation is with the customer to ensure they adhere to their connection agreement requirements with the DSO while also meeting any further SEM obligations they choose to enter into.

Part D: Barriers to flexibility and the contribution of digitalisation

This part of the report identifies and assesses regulatory and market design barriers that restrict the participation of flexibility in the electricity market and assesses the role of digitalisation in either contributing to or solving these barriers.

This section of the report has been drafted in alignment with Article 19(e)(2) points (c) and (d) of Regulation (EU) 2019/943 (as amended by Regulation (EU) 2024/1747) and reflects the requirements set out in the ACER Methodology and supporting recommendations.

In March 2026 ACER published a Recommendation on NRAs' reporting on barriers for non-fossil flexibility. In line with this recommendation the barrier assessment in this report considers:

- Regulatory and market design barriers across the categories defined in the ACER framework, including barriers to market access, the provision of flexibility services, and administrative requirements.
- The extent to which aspects of network tariff design may unduly restrict demand response, including tariff structures, differentiation between active and non-active customers, and the application of exemptions or discounts.

The analysis draws on findings from engagement across the CRU, alongside detailed inputs from EirGrid and ESB Networks based on their own internal assessments, operational experience, modelling insights and information gathered through relevant industry forums, and input from the representations made by industry in response to the published FNA information note. These inputs highlight that as the system evolves towards higher shares of variable renewable generation and increased participation of non-fossil flexible resources, existing market, operational and regulatory arrangements will be required to evolve.

Digitalisation is considered throughout the assessment as both a potential enabler and, where gaps exist, a contributing factor to barriers. Improvements in data availability, forecasting, visibility, automation and system coordination have the potential to facilitate participation of flexibility, while limitations in these areas may reinforce existing challenges. Effective deployment of digital solutions will require integration with operational and market frameworks, supported by appropriate coordination between transmission and distribution system operators.

The findings of this assessment highlight that significant progress has already been made across the Irish system in enabling and supporting a more flexible, low carbon electricity system. In particular, system operators and policymakers have advanced the development of flexibility markets and products, enabled flexible resources in the wholesale market arrangements, progressed procurement and consultation processes for long duration storage and demand response, and they have progressed stronger coordination across the transmission and distribution network. These developments demonstrate that, while barriers remain, the Irish framework for enabling flexibility is evolving and maturing in parallel with the increasing penetration of renewable generation.

In presenting these findings, barriers are assessed in a technology- and flexibility-type agnostic manner to provide an overarching view of the key constraints across the system. It is important to note that these barriers do not apply uniformly across all forms of flexibility; rather, their relevance and impact vary depending on the specific flexibility type, use case and location. Where appropriate, the analysis highlights whether particular barriers are more closely associated with system-level, transmission-level or distribution-level flexibility needs, to support a clearer understanding of where targeted action may be required.

10. Regulatory and market design barrier assessment process

10.1 Identification process

The CRU coordinated the overall approach to barrier identification which included:

- Providing direction to ESBN and EirGrid on the scope and type of inputs required for the assessment.
- Undertaking a data gathering exercise across the CRU to capture a broad range of regulatory perspectives and considering the representations made by industry in response to the published FNA information note.
- Consolidating CRU internal views alongside evidence and analysis provided by ESBN and EirGrid, to develop a coherent, system-wide view of barriers.

This approach ensured that the assessment reflects both internal regulatory insight and evidence from the System Operators.

EirGrid and ESB Networks each undertook separate but structured assessments to identify and evidence barriers through engagement with subject matter experts. EirGrid carried out a cross-functional internal review, drawing on subject matter expertise across market, operational and regulatory areas and mapping identified barriers to the ACER framework using a consistent evidence-based approach. In parallel, ESB Networks conducted its own analysis focused on distribution-level barriers, drawing on internal assessments, stakeholder engagement and pilot experience. This analysis similarly aligned with the ACER framework where applicable, while also capturing additional barriers. As part of this process, ESB Networks engaged with members of its Advisory Council on the Article 15 market barriers assessment in Q4 2025. Feedback was received from one respondent and, where relevant, has been reflected in this report.

10.2 Assessment of regulatory and market design barriers

In line with the ACER Recommendation on NRAs' reporting on barriers for non-fossil flexibility the identified regulatory and market design barriers have, where possible, been grouped according to the six ACER-defined barrier categories. These are:

1. Lack of proper legal framework for market access to new entrants and small actors.

2. Lack of enablers and incentives to provide flexibility.
3. Restrictive requirements to provide balancing services.
4. Restrictive requirements to provide congestion management.
5. Complex, lengthy, and discriminatory administrative requirements.
6. Lack of regulatory incentives to system operators to consider non-wire alternatives.

The ACER Recommendation also defines a set of specific indicators for each barrier category. Where barriers identified in this assessment align with a particular indicator, this has been highlighted accordingly.

Where a barrier was identified that did not clearly align with the ACER categorisation, this has been presented separately outside the defined categories.

As stated in the introduction to this section, the barriers are assessed in a technology- and flexibility-type agnostic manner to provide an overarching view of the key constraints across the system. As such, certain identified barriers may be more relevant to specific forms of flexibility and may have varying degrees of influence on the flexibility needs identified in this assessment. Certain barriers were identified consistently across the CRU, EirGrid and ESB Networks assessments while others were only identified by one of those assessments. As such, certain barriers covered in this report will be more relevant at transmission or distribution network level or wider system level than others. The CRU has consolidated these findings to provide an overarching system-wide view of the key barriers, and the specific application or relevance of individual barriers is not always explicitly distinguished within this section.

Significant work is already underway across policy, regulatory, market and operational frameworks to facilitate greater participation of flexible resources. Accordingly, the purpose of this section is not to provide a comprehensive overview of all ongoing initiatives, but rather to highlight areas where barriers to flexibility have been identified and where further consideration or action may be required. This summary of the identified potential barriers to flexibility does not represent a view on the relative importance or urgency of resolution of individual barriers; rather, it is intended to meet ACER requirements and provide a comprehensive, system-wide overview of the range of potential barriers identified.

11. Regulatory and market design barrier assessment findings

11.1 Market Barrier 1 – “Lack of proper legal framework for market access to new entrants and small actors”

The Electricity Directive requires Member States to establish enabling regulatory frameworks for active customers, market participants engaged in aggregation, Citizen Energy Communities and Renewable Energy Communities, including arrangements that allow them to participate in electricity markets directly or through aggregation.

Ireland has established much of the legislative basis required to enable these actors to participate in electricity markets, and the review completed for this barrier assessment did not identify any general legal prohibition on participation by active customers, aggregators, independent aggregators or energy communities in the SEM. However, legal eligibility does not necessarily provide all actors with a clear or practical route to participation. While established participants, including DSUs and batteries, can already access a number of SEM markets and services through existing market and operational arrangements, further development of the regulatory framework for aggregation and demand response is required. This includes work in relation to licensing, customer protection, roles and responsibilities, and integration with existing market arrangements for independent aggregators and other emerging participants. Industry responses to the FNA Information Paper raised the need for clearer and more enduring roles, responsibilities and governance for new actors, alongside practical access issues affecting storage, aggregation and demand-side participation. Relevant work is being progressed through the CRU’s National Energy Demand Strategy, including Action 1.13 on licences for aggregation and demand response.

The issues identified under this barrier arise at different levels. In several areas, the underlying legal rights and eligibility requirements are in place, while the detailed regulatory, market and operational arrangements needed to exercise those rights remain under development. The relevant next steps may therefore require action across legislation, CRU regulatory development, SEM market reform and system operator implementation.

11.1.1 Development of an enduring flexibility framework

(Corresponds to ACER indicator 1.1 - *Main roles and responsibilities of new actors not defined*)

Statutory Instrument (SI) No. 76 (2022) and SI No. 20 (2022) provides a legislative basis for active customer participation and aggregation. SI No. 366 (2022) also defines aggregation and independent aggregation and establishes relevant protections for customers entering aggregation contracts. Established flexibility resources, including Demand Side Units and batteries, can participate in a number of SEM markets and system services. However the current frameworks do not yet provide the comprehensive, durable structure needed to support sustained market development. In particular, further work in developing the market rules of the Trading and Settlement Code and TSO IT systems is required to facilitate the full participation of flexibility sources, such as storage and DSUs. Further work is also required on the detailed regulatory treatment of different flexibility resources and emerging market actors, including licensing, customer protection, roles and responsibilities and integration with existing market arrangements. There is no distinct licensing arrangement for established market participants such as Demand Side Units (DSUs) and batteries, nor for emerging categories such as energy communities. This gap may contribute to uncertainty for prospective flexibility service providers (FSPs) and may deter entry.

ESB Networks noted that flexibility continues to be perceived as a pilot or early-stage activity rather than an enduring market arrangement. The absence of a dedicated flexibility code, or a clear and stable long-term framework governing participation, creates uncertainty for new entrants and smaller actors who need regulatory predictability to make investment and operational decisions. ESB Networks currently anticipates that in order to evolve and scale flexibility markets, a substantial programme of work will be required across several key, external stakeholders on the treatment of flexibility and demand response in the regulatory framework, existing markets and the market systems which underpin the market design and processes.

Work is ongoing through the National Energy Demand Strategy, including actions relating to licences for aggregation and demand response and the development of a framework for market participants that do not fit within existing electricity licensing arrangements, alongside EirGrid-led work to improve the participation and performance of Demand Side Units in electricity markets and to develop arrangements for long-duration energy storage. The other key area of work in this regard is ensuring that all market participants, including flexibility providers, have equal access to all markets. As this work progresses, further consideration may be required to ensure that the relevant legislative, regulatory, SEM and system operator arrangements operate coherently and support participation by new technologies and smaller or distributed resources. This may warrant further examination alongside the development of the indicative national flexibility objective and future FNAs.

11.1.2 Limited Aggregation Framework

(Corresponds to ACER indicator 1.1 - *Main roles and responsibilities of new actors not defined*)

Aggregation is a key enabler for smaller, SME and domestic customers who may be unwilling or unable to contract directly with the DSO due to operational, technical or administrative complexity. Smaller demand-side resources and distributed assets may require aggregation to meet market entry and compliance requirements; for example, Grid Code requirements for DSUs to meet minimum size thresholds (≥4 MW, either as a single site or via aggregation). The limited presence of aggregators in the Irish flexibility market was identified as a potential barrier to participation for smaller flexible service providers.

Aggregation is currently an established feature within the wholesale market through the Demand Side Unit (DSU) model, whereby multiple demand sites can be combined to meet participation requirements under defined rules and thresholds, however beyond this the wider aggregation market remains less developed. While the DSU model is established, the policy and regulatory framework for broader aggregation models, including independent aggregators and retail-level aggregation, continues to evolve. Further clarity on roles, governance and interoperability would support wider market participation. While legal powers to enable aggregation broadly exist, an enabling policy and regulatory framework has not yet been implemented in practice, which limits routes to market for active customers and energy communities. Feedback received from one respondent through the ESB Networks Advisory Council engagement noted that there is currently no shared definition of what an Aggregator is or what it can do, and that opening the market to Independent Aggregators at the retail level could unlock innovation that current suppliers lack the agility or incentive to deliver.

In practice, participation in aggregation is currently constrained to existing structures (for example, via DSUs), with changes likely required to support broader participation and scaling over time. In addition to this limited revenue certainty, constrained opportunities for value stacking, and the absence of equivalent customer protection and market arrangements for aggregated resources also may limit the development of viable aggregation models.

Action 1.13 of the National Energy Demand Strategy ("Licences for aggregation and demand response") proposes consultation on the development of new licences for aggregation and demand response. This action is linked to the broader objective of the NEDS to increase demand flexibility across the system and reflects the need to put in place a regulatory framework that enables new market participants to provide flexibility services to customers.

11.1.3 Integrated Hybrid Assets – market access

(Corresponds to ACER indicator 1.1 - Main roles and responsibilities of new actors not defined)

Current market and connection arrangements do not provide a clear route for integrated hybrid assets to participate as a single market-facing resource. The CRU's MEC sharing decision[63] enables co-located hybrid projects, but only where each technology remains separately registered, sub-metered and dispatched. Integrated Hybrid Projects, where multiple technologies would operate as a single unit for market, settlement and dispatch purposes, are explicitly outside the scope of that decision. This indicates a continuing barrier to technology-neutral market access for assets seeking to combine generation and storage as an integrated resource.

11.1.4 Energy Communities – Lack of participation pathway

[63] Decision on Sharing Maximum Export Capacity (MEC) behind a Single Connection Point | CRU.ie

(Corresponds to ACER indicator 1.1 - *Main roles and responsibilities of new actors not defined*)

Citizen Energy Communities and Renewable Energy Communities are recognised in Irish legislation and have rights to undertake activities including generation, consumption, aggregation, energy storage and the sale of electricity. The relevant legislative provisions are contained in SI No. 76 of 2022, which gives effect to relevant provisions of the Renewable Energy Directive and Articles 15 and 16 of the Electricity Directive. The primary and secondary legislative basis for energy communities is therefore in place.

However, the lack of enabling framework and the absence of a dedicated licensing and participation pathway for energy communities was raised as a potential barrier which limits their ability to access flexibility markets. While SI No. 76 (2022) envisages a role for citizen energy communities and renewable energy communities in the energy system, the enabling framework for these actors to access flexibility markets in practice has not yet been implemented. There is a lack of an established or clearly signposted route through which energy communities can engage as flexibility service providers, which represents both a legal gap and a practical barrier to entry for this emerging category of market participant. This is a recognised area where further work is required, in particular through NEDS Action 1.14 which is intended to establish a framework for new market participants that do not fit within existing electricity licensing arrangements to enter the market and provide services to customers.

11.2 Market Barrier 2 – “Lack of enablers and incentives to provide flexibility”

A range of metering, tariff, market and product arrangements already provide a foundation for flexibility participation in Ireland. These include the ongoing smart-meter rollout, time-of-use tariffs, wholesale, balancing, capacity and system-services arrangements, and emerging distribution flexibility products. The review completed for this barrier assessment did not therefore identify a general absence of incentives or enabling arrangements to provide flexibility. However, a number of barriers have been identified relating to sufficient economic enablers and incentives for flexibility participation. Industry responses to the FNA Information Paper also identified the clarity, predictability and completeness of economic signals as important to participation and investment.

The issues identified arise through both implicit flexibility, where customers respond to retail or network price signals, and explicit flexibility, where resources are remunerated for providing a defined market or system service. These align with the defined ACER Market Barrier indicators, in particular Indicator 2.1 (metering) and Indicator 2.2 (price signals) and also extend to other indicators not fully captured by the ACER indicator structure.

11.2.1 Wholesale and capacity market - Incentives and enablers

There are a number of existing approaches, such as the participations of DSUs and batteries in the balancing market, capacity market and system services arrangements, which give flexible resources the ability to participate in the wholesale market arrangements. The issues identified through this assessment are therefore not a general absence of incentives, but whether the available signals and market arrangements enable different forms of flexibility to respond efficiently and receive an appropriate share of the value they provide. EirGrids analysis suggests that there can be a lack of clear and targeted economic signals that would encourage investment in flexible resources and flexible operations, and in some cases the current market structures and administrative arrangements may still limit the deployment of flexibility.

One potential example of this is the non-energy costs for flexibility which increases demand consumption, either through demand side response or charging storage resources. For resources directly in the wholesale market this can be through increased application of wholesale market and network charges applied to demand. For resources which are providing implicit flexibility outside of the wholesale market this can be because of increased retail market charges with many elements of the relevant tariffs being fixed costs, particularly fixed volumetric charges, which do not reflect the value of energy or flexibility in that particular period. Detailed work and analysis is required to fully understand and quantify the actual impact of the application of certain charges and how these may incentivise or disincentivise the deployment of flexible solutions.

A further limitation relates to weak or incomplete price signals in wholesale markets, which may reduce incentives for demand-side participation or result in flexibility value not reaching the party delivering demand reduction. In particular, with Demand Side Units (DSUs) some of the wholesale energy market benefits are collected by electricity suppliers of the customers providing the flexibility rather than customers themselves (though they receive retail price benefits) or the flexibility service providers. This can reduce customer incentives to maximise availability to provide demand side response in the energy market arrangements.

The SEM Committee has identified issues relating to the treatment of DSUs within energy payment arrangements, including incentives for demand reduction at times of high prices and the ability of DSUs to compete on an equal footing with other participants. This can contribute to an incomplete revenue stack for flexibility providers and may reduce efficient participation in response to system needs and market signals. In response to these issues, the SEM Committee has undertaken a programme of work on DSU energy payment arrangements, including consultation and proposed decisions to introduce explicit energy payments and supplier compensation mechanisms. These changes are intended to address existing incentive distortions and reward DSUs that deliver value to the system.

A further consideration is the participation of suppliers in the wholesale market and whether the incentives and price signals faced by suppliers remain sufficient given recent market changes, such as the roll-out of smart meters. Given the potential for implicit flexibility to provide cost-effective flexibility this is an area that could be given further consideration.

Progress has been made to facilitate the participation of storage resources in electricity markets and system operation, however further development may be required to enable their full participation. At present, the interim "follow Physical Notification (PN)" approach is used, whereby storage dispatch is aligned as closely as possible with the operating profile submitted by the storage operator. This approach has been implemented to help ensure that dispatch schedules remain consistent with the physical energy limitations of storage resources. While this provides an interim solution, it can limit the ability of system operators to fully utilise storage resources when managing system needs and network constraints. As storage deployment increases, further development of market systems and operational processes may be required to support the full and efficient participation of storage resources and realise the full flexibility value they can provide to the electricity system. Industry responses to the FNA Information Paper also supported the need for an enduring solution to enable efficient participation of storage in the market. This is likely to become increasingly important as further work progresses on frameworks to support the deployment and participation of long-duration energy storage, including EirGrid's ongoing work to develop a Long Duration Energy Storage (LDES) framework.

11.2.2 Time of Use Tariffs

Limited uptake of time of use (ToU) tariffs acts as a market barrier to demand side flexibility. Internal CRU analysis indicates that, as of June 2026, 21% of customers with smart meters are on ToU-type tariffs. While this figure is increasing month on month, uptake remains relatively low despite a policy focus on increasing uptake. Low uptake reduces the effectiveness of ToU tariffs as a driver of active demand participation, limiting their contribution to unlocking flexibility at scale.

11.2.3 Metering infrastructure and sub-metering

(Corresponds to ACER indicator 2.1 - *Lack of adequate metering systems*)

Ireland has made substantial progress in deploying smart meters. As of April 2026 there have been over 2.1 million smart meter installations completed (including 2,065,800 household and 87,854 non-household customers), and over 80% of households with a smart meter installed. For the large majority of deployed smart meters, the review found that the principal minimum functionalities considered by ACER are available, including time-of-use consumption information, validated historical data, separate accounting for import and export, and the provision of data to customers and authorised third parties under the applicable arrangements. This rollout provides a strong foundation for customer participation in flexibility services. Building on the successful rollout of smart metering, ongoing implementation of the Smart Meter Data Access Code, and enablement of the P1[64] port initiatives are expected to enable customers to access real-time data and support participation in flexibility services. In parallel, the continued implementation of the requirements under the Electricity Directive are expected to further enhance customer access to energy data and participation in flexibility markets. While these developments are expected to make progress on existing limitations, regulatory policy, market design and implementation requirements for secondary metering and dedicated measurement devices (DMDs) remain under development. Until these arrangements are fully

[64] The P1 port provides customers with access to near real-time data through the connection of a compatible device.

implemented, some limitations may remain regarding the granularity of data available for observability and the participation of smaller distributed resources.

Further to this, in order to facilitate and ensure accurate energy market settlement there is a requirement to have smart metering, baselining, and evidence standards that may be difficult and expensive to meet at small scale to measure the actual response of demand side response resources.

11.2.4 Incomplete economic signals, limited market value for flexibility and revenue uncertainty

(CORRESPONDS TO ACER INDICATOR 2.2 – *ABSENCE OF PRICE SIGNALS*)

The absence of clear and reliable economic signals has been consistently identified as a deterrent to flexibility participation across multiple customer segments. This is consistent with ESB Networks findings which note that the Demand Flexibility Product (DFP) has generated genuine interest primarily because it offers revenue certainty through contracts of approximately 15 years. By contrast, initiatives framed as pilots tend to suppress investment decisions, as customers in certain sectors are generally unwilling to commit to operational changes where the return on investment is unclear or where revenue streams have proven volatile.

Upfront capital requirements for assets such as solar generation, heat pumps, and behind-the-meter battery storage present a further practical barrier, particularly for smaller businesses. Qualitative customer research completed by ESB Networks found that some smaller retailers are unwilling to invest in battery systems without clearer revenue visibility, and that across retail, hospitality, and manufacturing, demand side flexibility economics are widely seen as unclear, with participants indicating that demonstrable cost savings are a prerequisite for engagement.

In addition to the recent round one procurement of the DFP, ESB Networks is currently consulting on two proposed medium term flexibility products, within a single framework called Local Business Flex (LBF) which are designed to help manage local network congestion in selected areas and which ESB Networks intends to bring to market in 2026, dependent on CRU approval.

EirGrid further note that the day ahead and intraday SEM markets clear on unconstrained forecast conditions without recognition of locational network constraints and frequently requires correction in real time through redispatch and balancing to accommodate operational constraints and system needs. As a result, some day ahead positions do not reflect physical availability on the system, particularly where commercial trading positions are disconnected from real world operational constraints. The absence of day ahead price coupling with GB further increases divergence between market outcomes and physical system requirements. This lack of locational signals can diminish incentives for flexible resources to develop in ways and locations such that they could help meet locational flexibility needs (such as network congestion) and in some cases could actually drive an increase in the volume of such needs if resources (flexible or otherwise) have nothing preventing them from locating where they could worsen network congestion.

The points above reduce the potential for flexible resources to provide their full value to create more efficient market outcomes.

Battery storage has contributed to system flexibility including through ex-ante market trading in recent months since implementation of the relevant tranche of the Scheduling and Dispatch Programme (SDP_02 Mod_02_24). The SDP modifications are a positive step for flexible storage resources allowing them to notify intended charging and discharging schedules. Work is needed to further evolve products and balancing market initiatives to better reflect the full value of flexibility, while targeting this flexibility to meet system needs, including through the provision of locational signals. EirGrid is currently consulting on a dedicated LDES product to provide the electricity system with a source of flexibility, with a target to achieve delivery of LDES units by 2030, dependant on CRU approval.

11.3 Market Barrier 3 – "Restrictive requirements to provide balancing services"

A number of ongoing projects are intended to improve the participation of flexibility resources, including storage and DSUs, in the ex-ante and balancing markets. Implementation of the European balancing framework is continuing, with FASS[65] intended to introduce day-ahead procurement of balancing capacity and support greater alignment with European balancing requirements. However, the SEM balancing arrangements retain specific features reflecting the centrally dispatched market design and system-operation approach. For example, currently standard Balancing Energy products are not procured in the Balancing Market. The extent to which these arrangements affect flexibility or the participation of new technologies has not been established through this assessment and may warrant further examination as FASS is implemented and through future FNAs.

11.3.1 Dispatch, Control and Operations

EirGrid noted that operational requirements on controllability, telemetry, response times, and availability have often been designed around typical generation types and may not be appropriate to accommodate smaller, distributed or aggregated resources. There may be a level of costs and operational and testing complexity associated which have a proportionally greater impact on smaller flexible resources. As the electricity system evolves to incorporate increasing volumes of small-scale and distributed flexibility sources, including multiple technologies located behind the meter, there may be a need to review whether existing participation requirements and operational approaches remain appropriate, and how they can

[65] Future Arrangements for System Services

evolve to support broader participation while maintaining system security and operational effectiveness.

Improvements in real time visibility, latency in data flows, trusted availability signals, and automation for small scale resources could improve the efficient use of DSUs and small generators. As the volume of smaller and aggregated resources increases, further development of automated dispatch and information-exchange capabilities may be required.

It is also not currently possible for the System Operator to model the precise locational impact of dispatching a DSU where the DSU comprises an aggregation of sites across the network and the aggregator determines which individual sites respond. The System Operator engages with the DSU as a single aggregated market unit and may therefore have limited visibility of the location of the delivered responses. This may limit the extent to which the locational impact of DSU dispatch can be anticipated or reflected in operational decision-making. The implications of limited visibility of the underlying DSU portfolio should also be considered within Market Barrier 4 – 'restrictive requirement to provide congestion management'.

11.3.2 Grid code and technical requirements

EirGrid noted that modifications to the Grid Code, Distribution Code and other technical requirements continue to evolve as the power system transitions away from a small number of large, controllable generation units towards a more distributed mix of demand, embedded generation, and smaller flexible resources. In particular, demand facilities are often not subject to Grid Code level stability requirements for example Fault Ride Through, Active Power Recovery, and Rate of Change of Frequency (RoCoF) capability. For Large Energy Users (LEUs), this can have a large impact on the power system which reduces confidence in their abilities during system disturbances and limits their qualification to provide balancing services.

Ongoing work to progress proposed Grid Code and related Distribution Code updates for Fault Ride Through requirements for Large Energy Users could be an enabler to allowing these resources to provide flexibility. The proposed changes are intended to allow emerging and untraditional flexible resources in the form of Large Energy User demand sites to deliver capability within Grid Code requirements.

11.4 Market Barrier 4 – "Restrictive requirement to provide congestion management"

A number of initiatives are under way to increase the role of flexibility in congestion management. At transmission level, constraint and curtailment actions affecting both priority-dispatch and non-priority-dispatch resources are currently treated as non-market-based redispatch under the SEM design. Market-based actions may be taken where available resources can address the relevant system need before the applicable non-market-based redispatch arrangements are used. The current approach reflects SEM Committee decisions on the implementation of Regulation (EU) 2019/943, with further work required to progress the enduring arrangements for market-based redispatch. Considering the results of the flexibility needs assessment, the CRU may consider whether further market efficiencies could be developed. In light of the significant role of network constraints identified in the assessment, consideration could also be given to whether market-based congestion management products may help reduce the need for redispatch and support a more efficient use of flexibility resources.

At distribution level, ESB Networks is developing and using a range of approaches to manage local congestion, including market-based flexibility procurement, flexible connection arrangements and other operational measures. These include the Demand Flexibility Product, Local Business Flex, Flexible Demand Connection pilots, managed EV charging, SME Flex and the investigation of Conservation Voltage Reduction. The arrangements are at different stages of development and implementation.

The review did not establish that the current transmission or distribution arrangements necessarily restrict flexibility participation. However, further examination may be appropriate of the enduring approach to transmission redispatch and of the effectiveness, scalability and accessibility of DSO flexibility arrangements as the relevant products and markets develop. Industry responses to the FNA Information Paper also highlighted the locational nature of transmission congestion and the potential for appropriately located flexibility resources to complement, or in some cases provide an alternative to, network reinforcement.

Barriers specific to DSO congestion management

ESB Networks analysis identified a number of barriers specific to DSO congestion management that broadly align with ACER Market Barrier 4, particularly Indicator 4.2 (DSO congestion management) and Indicator 4.3 (constraints in local markets).

11.4.1 Procurement process requirements

(Corresponds to ACER indicator 4.2 - *Unjustified lack of market-based DSO congestion management*)

As a public body, ESB Networks is required to procure flexibility services through the national eTenders platform in compliance with the Utilities Directive and the Office of Government Procurement’s electronic tendering requirements. While this route is market-based in nature, it presents a substantial administrative barrier for prospective FSPs particularly smaller and community-based actors.

Engagement with existing FSPs has confirmed that the eTenders process is extensive and that the administrative burden is sufficient to cause some providers to question whether participation is worthwhile. FSPs have indicated they do not have the internal resources to manage formal tendering processes of this nature. In 2025, ESB Networks undertook an exercise focused initially on energy communities to identify challenges in the qualification process for flexibility market participation. The principal finding with broader applicability across all FSP categories is that ESB Networks is bound by the eTenders process for the foreseeable future and that many qualification criteria, including those relating to GDPR compliance and cybersecurity, cannot readily be simplified. ESB Networks currently anticipates that in order to evolve and scale flexibility markets, a substantial programme of work will be required across several key, external stakeholders on the treatment of flexibility and demand response in the regulatory framework, existing markets and systems which underpin the market design and processes.

This point is also applicable to Market Barrier 5 – 'Complex, lengthy and discriminatory administrative requirements'.

11.4.2 Localised nature of DSO needs and limited supply-side depth

(Corresponds to ACER indicator 4.2 - *Unjustified lack of market-based DSO congestion management*)

ESB Networks operational analysis highlights that network constraints in the distribution system are highly localised. This means that the available pool of eligible flexibility resources within a geographically constrained area may be limited, reducing competitive depth in DSO procurement exercises and increasing the risk that services cannot be sourced at all in certain locations. This structural characteristic of DSO flexibility markets distinguishes them meaningfully from TSO-led markets, where resource pools are larger and more geographically dispersed.

Relatedly, ESB Networks notes that industry capability, experience, and commercial focus in the flexibility space remain more closely aligned with TSO-led markets and products. DSO requirements are generally smaller in scale, and potential FSPs may not view DSO congestion management as a primary commercial opportunity, further constraining the effective supply of flexibility services to the distribution network.

11.4.3 Market architecture evolution and gaps

(Corresponds to ACER indicator 4.3 - *Constraints in local markets for TSO/DSO congestion management*)

There are a number of outstanding and ongoing changes to market arrangements — including those relating to non-priority dispatch renewables, DSU energy payments, new Capacity Remuneration Mechanism (CRM) arrangements, and the Future Arrangements for System Services (FASS) framework, particularly questions around mandatory versus voluntary participation. Each of these has the potential to help overcome certain identified barriers but may also add further uncertainty for prospective FSPs considering entry into DSO flexibility markets.

Customer segmentation analysis undertaken by ESB Networks also highlights sector-specific compliance and safety constraints that limit what flexibility certain customers can realistically offer. Use of refrigeration loads for flexibility can be limited by strict temperature compliance requirements in retail and hospitality. Pharmaceutical and food manufacturing processes typically require unbroken process control. Noise restrictions in some manufacturing locations limit nighttime load shifting, and protected buildings constrain upgrade options. These factors interact with product design requirements in ways that reduce the effective pool of flexibility available to ESB Networks at any given time and location.

11.5 Market Barrier 5 – "Complex, lengthy and discriminatory administrative requirements"

The review found that established connection and market-access procedures are in place, including online information, electronic connection applications, defined process deadlines and simplified arrangements for a number of smaller-scale technologies.

However, the existence of established procedures does not necessarily mean that all flexibility resources can connect or participate efficiently in practice. Available network capacity, connection timeframes, the treatment of emerging and combined technologies, qualification requirements and the cumulative complexity of participating across multiple markets and codes may affect the deployment of flexibility. A number of reforms and implementation workstreams are under way, but their effectiveness in addressing these issues may warrant further examination following this report and as part of future FNAs.

11.5.1 Inefficient grid connection procedures

(Corresponds to ACER indicator 5.1 - *Inefficient grid connection procedures*)

The review identified a number of established features within the connection framework. Information on connection procedures is available online, applications can be submitted electronically, and connection procedures may run in parallel with other required authorisations. The ECP-GSS framework also sets out relevant process deadlines, while simplified procedures are available for micro-generation, mini-generation, small-scale generation and household EV charging.

Limited available grid capacity and long connection timeframes can nevertheless act as fundamental barriers to the development of flexibility in Ireland. While flexibility may be specifically sought in constrained areas to help address network limitations, constraints can also increase the cost and time required to connect new flexibility assets. In practice, lack of available capacity and lengthy connection queues and the associated uncertainty can delay the deployment of storage, demand-side response and other flexibility resources, limiting the pace at which flexibility becomes available to the system.

In addition, whilst connection processes are broadly established, a lack of clarity and tailored pathways for specific demand technologies (e.g. heat pumps) may act as a barrier in practice. While standard processes exist, they are not always well adapted to newer or emerging flexibility technologies, which can create additional complexity and administrative burden for participation.

EirGrid noted that connection policies and network access arrangements could better enable the development of flexible resources. For instance, for hybrid co-located connections that have multiple technologies behind a single connection point, the rules and systems needed for visibility, controllability, verification and settlement are not yet developed to accommodate the sharing of MEC behind these different generator types. The need for each separate technology type to have a separate MEC which is summated at the connection point could be a barrier in terms of the costs to the applicant for that MEC, and also the ability for the network to accommodate that MEC, as it can result in a higher overall MEC request at the connection point than is efficient. In April 2026, the CRU published a decision to allow hybrid co-located projects to dynamically share a single MEC at a single connection point and directed the system operators to proceed with implementation. Along with the 2024 decision to remove the Installed Capacity Cap, this removes some of the barriers for hybrid projects. The Sharing MEC decision is expected to deliver several important benefits including but not limited to improved system flexibility by enabling storage and diversified generation at a single site to connect more efficiently. Following its publication, the system operators have published their joint implementation road map with work expected to commence in Q3 2026.

It should be noted that the sharing of MEC does not facilitate cross charging (energy sharing) between market registered generation and storage behind the connection point using excess available energy (e.g. during curtailment or constraint). Enabling this would require a wide-ranging set of changes across dispatch processes, metering and settlement, balancing-market design, system-operation practices. Arrangements to facilitate this require further consideration.

Grid connection inefficiencies may be particularly relevant to certain identified flexibility needs in this assessment which are highly localised and arise in areas where available network capacity is constrained. In this context, delays in connection processes and limited capacity at key nodes directly limit the ability of flexibility resources to deploy where they are most needed. As a result, certain flexibility solutions may not be capable of contributing to the 2028 and 2030 needs where they cannot secure a connection or be delivered in time.

11.5.2 Qualification trial process

EirGrid noted the potential for the Qualification Trial Process (QTP) to act as a barrier for new or innovative flexibility solutions due the current entry requirements for participants. The purpose of the QTP is to prove the capabilities of technology types to provide system services under real operational conditions before accessing normal system service market arrangements. Following successful completion of a trial any service provider providing a service in that way with that technology would be considered a “proven technology” and able to go into the normal system services qualification processes. The QTP supports connection of technologies that have reached a level of maturity, can meet testing requirements and can comply with the existing Grid Code/Distribution Code standards as the trials are conducted under real operational conditions. As a result, it may limit the ability to trial new or innovative solutions identified through Calls for Information which do not fit into that scope or cannot meet those standards.

While the potential to change the scope of the QTP may be somewhat limited, this may highlight the need to consider alternative avenues for proving capabilities more broadly. One area where these topics could be progressed is specific to energy storage – where the Electricity Storage Policy Framework Action #2 requires the creation of a “sandbox” for advancing technical knowledge of emerging electricity storage technologies. Work on this is progressing between EirGrid, ESB Networks and the Department of Climate Energy and the

Environment (DCEE). Similar "sandbox" concepts could be further developed with a broader scope to enable other new flexible technologies to prove their capabilities.

11.5.3 Disproportionate procedures and requirements for market access

(Corresponds to ACER indicator 5.2 - *Disproportionate procedures and requirements for market access*)

Beyond the procurement process addressed under Market Barrier 4, ESB Networks identified a further set of informational and administrative barriers that align with ACER Market Barrier 5.

The overall complexity of the Irish electricity market arrangements has been raised as a barrier, particularly when considered in relation to the scale of revenue opportunity currently available in DSO flexibility markets. Prospective FSPs may need to navigate participation in up to four different markets or arrangements in order to establish a financially viable position. Each of these is governed by a separate set of codes and obligations, and without ensuring the proper governance of interoperability between those codes, participation may be more challenging for smaller or newer providers who lack either the institutional legacy knowledge or the headcount to absorb the full complexity of the Irish energy market landscape. Whilst adherence to multiple relevant codes will remain a requirement, some of the associated challenges are looking to be mitigated in the Network Code for Demand Response.

A related issue is the perceived absence of a coordinated approach across key industry stakeholders to communicate the benefits of flexibility and demand response for example consistency in terms of products and services, terminology. Ongoing work through the TSO-DSO Operating Model and JSOP is expected to help address some of these concerns.

There is also a misalignment between the types of flexibility services the network requires and what customers can realistically provide without material changes to processes or investment. Some services require response times or operational behaviours that are difficult for certain customer categories to meet, pointing to the need to better align product design with the actual capabilities and constraints of the prospective FSP base, while ensuring that network needs are still met.

11.6 Market Barrier 6 – "Lack of regulatory incentives to system operators to consider non-wire alternatives"

11.6.1 Regulatory incentives

(Corresponds to ACER indicator 6.1 - *Lack of incentives for SOs to consider non-wire alternatives*)

The regulatory framework includes a number of mechanisms intended to enable and incentivise system operators to develop and use flexibility and other non-wire alternatives. Regulatory incentives for system operators to consider non-wire alternatives over traditional capital reinforcement have in fact been strengthened through the enhanced PR6 Regulatory Framework, in particular through the decision to extend the flexibility (Capex/Opex) mechanism to the TSO. This framework allows network companies to adjust between capex and opex within the regulatory period and where it is efficient to do so, enabling network companies to select the most efficient solution rather than defaulting to Capex builds. While the DSO has carried out a procurement process for flexibility to relieve local congestion ahead of planned network development, the TSO has not yet developed a procurement process for non-wire alternatives.

As part of the DSO regulatory regime a dedicated CAPEX allowance has also been provided for Flexibility Market Transformations, supported by a delivery obligation and a dedicated flexibility incentive to encourage market development and utilisation. In addition, a regulatory mechanism now allows flexibility service payments for enduring products to be treated as recoverable costs, subject to defined conditions including alignment with FNA-approved volumes, avoidance of discretionary procurement beyond agreed needs, adherence with an established reserve price methodology, demonstration of efficient investment through CBA, and evidence that supporting systems and processes are operating effectively.

Together these frameworks ensure the regulatory regime supports and enables deployment of flexibility alongside traditional reinforcement. Further monitoring will be required to assess whether the PR6 arrangements result in the effective development and utilisation of flexibility and support efficient choices between flexibility, digital solutions and conventional reinforcement.

11.6.2 TSO-DSO operating model

EirGrid noted that effective incentivisation and management of flexibility will require close coordination between the DSO and TSO. This includes supporting the DSO's use of flexibility as a non-wire alternative to managing network congestion, while developing the near-term and real-time coordination capabilities needed to manage flexibility for whole-system benefit. As more distributed resources connect to the network, further development of data gathering and sharing between the DSO and TSO, visibility, controllability and the appropriate control of relevant resources will be required.

Further clarity is also required on how TSO and DSO arrangements interact, the processes and systems needed for operational coordination and communication, and the respective roles and responsibilities of each system operator. Relevant work is being progressed through the TSO-DSO Joint System Operator Programme (JSOP), which is incentivised under the PR5 and PR6 joint incentive framework.

11.7 Cross cutting barrier - Value Stacking and the Multi-Market Participation Challenge

Existing arrangements provide some opportunities for flexibility service providers to participate across multiple markets and services and, in some cases, to stack revenues. However, ESB Networks identified value stacking as a cross-cutting barrier, particularly where revenues from a single market, service or product are insufficient to support investment or where combining revenues across different arrangements is difficult in practice. The challenge is compounded by difficulties in simultaneously providing services to both transmission and distribution systems. Based on feedback ESB Networks received, the perceived challenges associated with stacking services have directly hindered participation in ESB Networks pilot programmes to date. This barrier spans multiple ACER market barrier categories and has been included here as a cross-cutting issue. Industry responses to the FNA Information Paper also supported the identification of value stacking and multi-market participation as a cross-cutting issue. Respondents raised both the importance of combining revenue streams to support viable investment and the practical challenge of managing potentially interacting obligations across multiple market and operational arrangements.

Within the current market design and European network code framework, resources generally need to attain revenue across multiple different services and value streams for their business case, rather than relying upon one or a smaller number of revenue sources. Each stream may have a different profile for revenue certainty or volatility, which may create uncertainty. Evidence gathered by ESBN across customer segments supports this and indicates that participation typically depends on the availability of multiple, complementary value streams. In the cement, pharmaceutical, and data centre sectors, for example a financial incentive alone is rarely sufficient, with sustainability or compliance drivers also influencing participation. Retailers require a combination of DSF revenue, efficiency savings, and resilience benefits before a business case stacks up. Where revenue streams are volatile as reported in the retail battery storage context, financial planning may become too uncertain to support investment.

Within this context, the ability to combine value streams across markets is an inherent feature of the market design. However, feedback indicates that stacking services simultaneously across TSO and DSO markets remains challenging in practice, particularly for larger customers and DSUs. As market arrangements mature and participation increases among SMEs, LEUs, and XLEUs, the need to enable more effective stacking of services is expected to become more pronounced.

Addressing these challenges requires coordinated arrangements that enable services to be stacked where technically and operationally compatible. This requires coordination between the wholesale, local-flexibility and retail layers of the electricity system, including across market rules, product design and governance arrangements. TSO-DSO coordination during the design of these arrangements is important to ensure that they operate coherently across the relevant markets and services.

Under the Joint System Operator Programme (JSOP) established by both ESB Networks and EirGrid in 2021, both System Operators are collaborating to - amongst other issues - identify and address barriers which hinder participation across markets. This topic has been the subject of extensive consideration by ESB Networks and EirGrid through development of the TSO-DSO Operating Model detailed conceptual design. Good progress has been made and that work is ongoing, with the overarching objective of developing agreed optimal stacking and coordination approaches for local flexibility services and wholesale market arrangements from a whole-of-system perspective. The key challenge is to avoid conflicting obligations and ensure that resources can comply with DSO operating requirements while also fulfilling their SEM market commitments. A recent example of a positive outcome of such work is the ESB Networks Demand Flexibility Product approved by CRU decision (CRU202560) in May 2025, which stated (following detailed discussions between the TSO, DSO and RA) that flexibility service providers will be permitted to participate in multiple markets and stack revenues.

The importance of value stacking is closely linked to the temporal characteristics of some of the identified flexibility needs in this assessment. The results show that many needs are concentrated in specific periods and locations, meaning assets may only be utilised for limited windows throughout the year. Where needs are “blocky” or intermittent, revenues from a single service may be insufficient to support a viable business case. In this context, access to compatible value streams may therefore be important to the commercial viability of resources meeting specific needs that arise only during limited periods.

12. Impact of network tariff structures

In line with the ACER methodology, this assessment considers the role of network tariff structures in enabling or restricting the development of flexibility. Network tariffs form a significant component of overall electricity price signals faced by consumers and market participants. For some customers, the level, structure and visibility of network charges can influence both short-term behavioural responses, such as demand shifting, and longer-term investment decisions.

Given the ongoing CRU-led Electricity Network Tariff Structure Review, this report does not provide a comprehensive assessment of tariff design. Instead, it sets out high-level observations on the interaction between network tariff structures and flexibility, recognising that detailed consideration of future tariff reform is being progressed through a dedicated regulatory process.

Assessment considerations on the impact of network tariff structures:

- Network tariffs can influence flexibility by affecting the price signals seen by consumers and market participants. Ireland has already introduced a peak time-of-use element into network tariffs for defined customer groups, commencing in the 2022/23 network tariff year. In Ireland, network tariffs are levied on suppliers, who decide how to pass these costs to end customers as part of their development of retail tariffs. Further reform may still be needed to strengthen the cost-reflectivity and visibility of network tariff signals, including the extent to which tariffs reflect periods of higher network demand or network cost. This is relevant to flexibility because clearer and more cost-reflective signals can support more efficient use of the network and may improve the incentive for customers to shift demand where it is efficient to do so. Also volumetric charges, at times when the network is not congested, can disincentivise customers, such as industrial heat, from increasing demand, even at times of low wholesale prices.

Electricity Network Tariff Structure Review:

The CRU is currently progressing Phase 1 of its Electricity Network Tariff Structure Review, which is expected to be delivered as a phased, multi-annual programme. Phase 1 will decide the objectives, principles and scope of the review, and include publication of a roadmap setting out the work and expected timelines for subsequent phases.

The review reflects the need to ensure that network tariff structures remain fit for purpose in the context of significant system transformation, including increasing levels of renewable generation, growing electrification of demand and the need for more efficient use of network infrastructure. The final design of network tariffs and the timing for their introduction have yet to be determined. The CRU will continue to keep stakeholders updated on the project, including timelines, to support engagement and an understanding of the timelines for consultations and decisions regarding the review.

13. Contribution of digitalisation

Digitalisation is recognised as an effective tool to help overcome some of the barriers raised in this section of the report and a key enabler for the future development and operation of flexibility markets. It is noted that CRU will take on some oversight responsibilities for certain aspects of the use of Artificial Intelligence in its regulated sectors within the context of a distributed regulatory framework in Ireland, in line with the EU Artificial Intelligence Act (Regulation (EU) 2024/1689)[66] and S.I. No. 366/2025[67]. The development of this regulatory framework, including the establishment of the AI Office of Ireland, is still in its early stages.

13.1 EirGrid view on the role of digitalisation

EirGrid considers digitalisation to play an important role in addressing barriers to flexibility. The

[66] Regulation - EU - 2024/1689 - EN - EUR-Lex
[67] S.I. No. 366/2025 - European Union (Artificial Intelligence) (Designation) Regulations 2025

increasing volume and diversity of smaller, distributed and aggregated resources will require enhanced digital systems, improved real-time visibility, observability, and greater automation to support their integration into market and operational arrangements.

Enhanced digital control and telemetry can support the verifiable aggregation of smaller assets at scale, reducing administrative and equipment costs while enabling these resources to meet performance requirements. Digitalisation can reduce settlement barriers for new entrants and small actors by improving how demand response is measured, verified and paid for. Improved data analytics and ex-post analysis of demand reduction dispatch decisions can enable supplier corrections for unconsumed energy to be identified and applied, improving confidence that value is allocated to the correct party.

Digitalisation can also strengthen incentives for flexibility through improved measurement, baselining and verification of demand flexibility. EirGrid noted, however, that these arrangements would need to be embedded within real-time operational and ex-post settlement systems supported by secure, low-latency signalling and robust cyber security arrangements.

From an operational perspective, EirGrid highlighted that digitalisation can support improved real-time availability and performance signals for DSUs and small-scale resources through additional data, automation and improved modelling. Improved forecasting, real-time visibility and constraint prediction capabilities could also help reduce divergence between ex-ante market positions and real-time operational requirements.

EirGrid further noted that improved visibility of storage and embedded generation, increased data sharing, and shared visibility between the TSO and DSO could support better coordination and alignment between market outcomes and real-time system operation, including the use of non-wire alternatives.

In relation to connections and hybrid integration, EirGrid highlighted that digitalisation can support more effective operational management through real-time monitoring, metering and coordinated control of hybrid sites. Enhanced monitoring and improved data collection could also support emerging technologies in demonstrating compliance through mechanisms such as the Qualification Trial Process (QTP).

EirGrid noted, however, that certain aspects of digitalisation could themselves create challenges for flexibility. In particular, the growth of data centre Large Energy Users could create barriers if those users are unable to meet Grid Code system stability requirements.

13.2 ESB Networks view on the role of digitalisation

ESB Networks considers digitalisation to be a key enabler for the future development and operation of flexibility markets. The increasing participation of distributed energy resources (DERs), active customers, aggregators, EVs, heat pumps, and battery storage will require enhanced digital systems, improved network visibility, and interoperable market platforms to support efficient coordination and participation at scale.

13.2.1 Smart meters and secondary metering

The National Smart Metering Programme provides a foundational digital capability supporting interval data collection, the facilitation of new types of innovative products and services in the market and improved network observability.

The introduction of secondary metering and its treatment in regulatory policy, market design, is currently being driven primarily by requirements contained in the Electricity Market Directive[68], which at this juncture, has not been transposed into Irish law. CRU's Call for Evidence on Conceptual Design for Energy Sharing and Multiple Supply Contracts[69] (CRU 202561) has sought views of external stakeholders on the introduction of more than one meter to facilitate customer sign-up to multiple supply contracts at a single connection point.

The introduction of secondary metering in Ireland will represent a substantial and complex programme of work, involving material changes to existing regulatory policy, market processes, industry systems, field operations and customer communications.

13.2.2 Flexibility Market Systems

ESB Networks is also progressing the development of Flexibility Market Systems (FMS) to support future operational and market processes relating to flexibility procurement and utilisation. The FMS is envisaged as supporting:

- Planned digital advertisement of flexibility needs through geographic mapping;
- Expanded communication methods relating to flexibility service utilisation events;
- Potential automation of flexibility service delivery validation;
- Potential automation of settlement processes; and
- Expanded reporting capabilities.

In parallel, the draft Network Code on Demand Response introduces requirements relating to the establishment of a Flexibility Information System (FIS). The FIS is envisaged as a common platform supporting the qualification and administration of flexibility service providers, Service Providing Units (SPUs), Service Providing Groups (SPGs), and Controllable Units (CUs).

The FIS would provide a single common access point for entitled parties to read, register, administer and update relevant information through harmonised graphical user interfaces (GUIs) and application programming interfaces (APIs). The framework also includes provisions relating to interoperability, data portability, and structured data export requirements.

From a DSO perspective, the continued development of smart metering, FMS, and FIS

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68 Electricity Market Directive 2024/1711
69 CRU2025261

capabilities will support the evolution of more scalable, interoperable, and digitally enabled flexibility market arrangements over time.

14. Barrier Assessment Key Findings

14.1 Regulatory and Market Barriers

The target years for this assessment are 2028 and 2030 and therefore reflect a relatively short term view of the flexibility needs of the system. While the quantified flexibility needs assessment is focused on the target years, the assessment of barriers has considered the longer-term future development of the electricity system and flexibility markets. As the identified needs are expected to increase over time as the share of variable renewable energy sources continues to grow, the barriers identified in this assessment are expected to become more material over time if not addressed.

Work is already underway across a number of areas to address these barriers and support the development of flexibility. This includes ongoing reforms to wholesale market arrangements (e.g. DSU energy payment developments), the introduction and scaling of new flexibility products (such as ESB Networks' Demand Flexibility Product), and structured programmes focused on improving system coordination (e.g. the TSO–DSO Joint System Operator Programme). In parallel, policy and regulatory initiatives relating to storage, aggregation, network tariffs and demand-side participation are progressing. These developments represent important steps towards establishing the frameworks, incentives and coordination arrangements required to support flexibility at scale, although many remain at an early stage of implementation.

Revenue stacking remains a key cross-cutting challenge. As reflected throughout the analysis, the ability to combine revenues across multiple markets and services is critical to establishing viable business models for flexibility. While steps are being taken to enable participation across different market layers, current arrangements do not yet consistently support efficient value stacking, which limits participation and investment.

Grid access and available capacity represent a fundamental constraint. In practice, the ability for flexibility resources to connect to and operate on the system is often limited by the availability of network capacity, irrespective of their technical capability to deliver system benefits. This means that the network itself can act as a binding constraint on the deployment of flexibility, despite flexibility having the potential to help manage network constraints and improve utilisation of existing network capacity.

Market access and grid code requirements can also create barriers to the participation of flexibility resources. Differences in technical, connection and operational requirements across technologies and participant types may increase complexity for new and emerging flexibility providers, including aggregated resources, integrated hybrids, Demand Side Units and battery storage. Continued work to standardise and streamline participation requirements, where appropriate, could support broader and more efficient participation in flexibility markets.

Creating effective and coordinated market arrangements for flexibility across a set of interacting electricity markets remains a central challenge. Ensuring that flexibility can access markets, receive appropriate signals and generate sufficient value is essential to enable participation, particularly for smaller and emerging resources. Current arrangements, including limited aggregation pathways, incomplete price signals and administrative complexity, indicate that this market is still developing and not yet fully mature.

Finally, effective coordination across the system will become even more critical. In particular, the development of a coordinated TSO–DSO operating model is essential to enable flexibility to deliver value across both system-wide and local needs. The TSO-DSO Joint System Operator Programme (JSOP) arrangements in Ireland aim to provide clear roles and coordination processes for operation between system operators. Standardised exchange of information and processes would ensure that distributed resources and flexibility are not only connected to the system but are also visible, controllable and usable by both system operators, improving confidence and supporting compliance with the future Network Code for Demand Response (NCDR).

Part E: Conclusion and Next Steps

This report sets out Ireland's first National Flexibility Needs Assessment, prepared in accordance with Article 19e of Regulation (EU) 2019/943 (as amended by Regulation (EU) 2024/1747) and the ACER Flexibility Needs Assessment Methodology. The assessment provides a coordinated, forward-looking evaluation of Ireland's anticipated flexibility needs across the electricity system and networks for the target years 2028 and 2030.

15. Summary of FNA results

The findings from this assessment demonstrate that flexibility will need to play an increasingly important role in supporting the secure and efficient operation of the Irish electricity system as renewable penetration increases and demand becomes more electrified. The assessment also highlights that flexibility needs are not uniform across the system, with different characteristics emerging at system, transmission and distribution level. Meeting or reducing these needs is likely to require a combination of flexibility resources, market and operational reforms, network development and targeted local solutions, depending on the nature, location and duration of the need.

15.1 Identified flexibility needs

The assessment identified flexibility needs across system, transmission and distribution levels, reflecting the changing operational characteristics of the Irish electricity system.

15.1.1 System level needs –

- The assessment identified substantial RES integration needs at system level, which increase as higher volumes of renewable generation are connected. These needs are reflected in increasing levels of RES dispatch down, driven by a combination of surplus renewable generation, operational constraints and transmission network congestion. While transmission constraints remain a significant driver of dispatch down in both target years, the contribution of wider operational constraints (in particular RES surplus) increases over time as RES penetration increases. The results identified that dispatch down events can occur over extended periods and exhibit "blocky" characteristics, indicating that flexibility needs are not limited to short-duration peak events.

15.1.2 Transmission level needs –

- The assessment identified transmission network constraints as a significant contributor to renewable dispatch down, particularly in the near term.
- By 2030, the share of dispatch down attributable to network constraints reduces from 88% in 2028 to 45% under WS28. This reduction is largely driven by additional transmission network development. Although constraints account for a lower proportion of dispatch down in 2030, they still represent a substantial share of overall dispatch down volumes. The results indicate that planned network reinforcements reduce the relative contribution of transmission constraints to overall dispatch down by

2030. However, flexibility remains important in supporting the management of localised congestion and operational constraints.

15.1.3 Distribution level needs –

- The assessment identified localised flexibility needs associated primarily with forecast station overloads and network congestion due to demand. Overall system-wide flexibility requirements are modest in energy terms, but materially concentrated in specific zones and stations, demonstrating that flexibility is likely needed to act as a targeted tool for managing localised network constraints rather than a system-wide energy resource. The total identified flexibility requirement is approximately 234 MW and 58 GWh in 2028, reducing to approximately 226 MW and 53 GWh by 2030, equivalent to around 0.14% and 0.12% of total all-island electricity consumption respectively.
- The identified needs are geographically concentrated, with Dublin North, Central and South accounting for a significant proportion of the identified requirement by 2030, while a small number of zones show no identified flexibility requirement. The assessment also identified potential wider network benefits associated with flexibility deployment, including positive impacts on local voltage profiles and support for more efficient operation of the distribution network.
- The assessment of downward flexibility needs at distribution level found that current levels of expected constraint associated with flexible generation connections and microgeneration are relatively limited, although these areas are expected to continue evolving over time as the system evolves.

15.2 Options to meet the identified flexibility needs

The analysis undertaken as part of this assessment indicates that a broad range of flexibility technologies and solutions could contribute to addressing the identified needs.

At system level, flexibility technologies such as energy storage, demand side response, flexible demand, interconnection and flexible generation can support renewable integration and reduce renewable dispatch down. The analysis demonstrates that different flexibility solutions are better suited to different flexibility requirements depending on the duration, timing and locational nature of the need, with increased flexibility capacity, particularly longer-duration flexibility, delivering the greatest value in reducing RES surplus and curtailment.

The distribution-level assessment finds that the most effective solutions for addressing identified distribution-level flexibility needs are highly locational and capable of responding during predictable congestion windows, with explicit demand response, shorter-duration battery storage and flexible demand connections identified as strong options for the local congestion needs. The report also highlights that flexibility solutions should not be viewed as direct replacements for traditional grid reinforcement in all cases, but rather as complementary tools that may defer or complement required network enhancement depending on the duration, certainty and location of the identified constraint. Longer-duration and system-scale solutions are generally considered less effective for highly localised distribution congestion, while digital and operational measures are identified as important enablers that improve the practicality, deliverability and value stacking potential of flexibility services.

The overall assessment highlights that the practical ability of flexibility resources to contribute to identified needs will depend not only on technical capability, but also on market arrangements, operational frameworks, digitalisation capabilities, connection processes and procurement design.

15.3 Market design and regulatory barriers and the role of digitalisation

The barrier identification and assessment process undertaken by the CRU, alongside ESB Networks and EirGrid, highlighted a range of regulatory, market and operational barriers across, and in some cases beyond, the ACER-defined barrier categories. These barriers vary in their relevance and impact across different flexibility types, use cases and time horizons, and will not all have an equal effect on the flexibility needs identified in this report. However, collectively they illustrate the key challenges in enabling flexibility to contribute fully to the Irish system.

The barriers identified include challenges relating to market access for smaller and newer participants, restrictive or complex administrative and connection processes, limitations associated with multi-market participation and value stacking, and the absence of sufficiently developed incentives and frameworks to support flexibility procurement and participation. The assessment also identified that network limitations and wider system constraints can themselves act as barriers to flexibility deployment and renewable integration, particularly where available network capacity and access is limited or delayed.

At the same time, the assessment also identified areas where progress is already being made, including ongoing market and regulatory reforms, pilot programmes and enhanced system coordination initiatives. These demonstrate that, while barriers remain, the Irish electricity system is actively evolving, with a clear trajectory towards addressing these constraints and enabling greater participation of flexibility over time.

Digitalisation is identified as an important enabler for future flexibility deployment and the development of flexibility markets. Improvements in real-time data, telemetry, automation, forecasting, visibility, system coordination and smarter network operation could help address barriers relating to market participation, settlement, operational visibility and the integration of distributed and aggregated resources. The report also highlights the importance of integrating digital solutions into operational and market processes as flexibility volumes increase.

16. Key findings

The key findings from Ireland's first National FNA are summarised below:

- The assessment highlights the important role flexibility can play in reducing renewable dispatch down, managing network constraints and supporting more efficient utilisation of renewable generation, particularly as renewable penetration increases towards 2030.
- The assessment demonstrates that flexibility will be important both in supporting system-wide operation and in addressing increasingly localised network constraints.
- At system level, the analysis demonstrates that increasing renewable penetration is expected to increase periods of renewable dispatch down and operational complexity, particularly during periods of high renewable output and lower system demand. The assessment highlights that flexibility requirements differ by duration, timing and operational need, with different forms of flexibility likely to be better suited to different use cases.
- The assessment also highlights important limitations and caveats associated with interpreting system-level flexibility results under the ACER methodology, specifically in relation to RES integration needs and ramping and short-term flexibility needs.
- Transmission network constraints remain a material contributor to renewable dispatch down and will continue to influence future flexibility requirements. The analysis demonstrates the importance of considering transmission network impacts alongside broader system-level flexibility needs and supports continued coordination between renewable integration analysis and transmission network planning. In this context the flexibility provided by non-wire solutions can be seen to provide benefits in advance of delivery of new infrastructure.
- The assessment demonstrates that renewable dispatch down can arise from a range of underlying drivers, including periods of renewable surplus, system operational constraints and transmission network congestion. These different drivers are likely to require different solutions and interventions. For example: surplus-related dispatch down may be reduced through market design improvements and increased market participation by flexible resources; operational constraint-related dispatch down may be reduced through improved system operation, dispatch and flexibility procurement arrangements; while transmission constraint-related dispatch down will continue to require a combination of network reinforcement and non-wire solutions. **The findings therefore highlight the importance of considering market, operational and network measures alongside flexibility deployment to support efficient renewable integration.**
- Distribution-level flexibility needs are concentrated in specific stations and zones, highlighting the importance of locational procurement approaches, local network visibility and targeted flexibility deployment. The analysis also demonstrates that flexibility can provide local operational and voltage support benefits in addition to addressing congestion.
- The assessment demonstrates that there are a range of potential flexibility solutions capable of contributing to the identified needs and reducing renewable dispatch down,

including storage, demand side response, flexible demand and other flexibility technologies. However, the analysis also highlights that some technologies and solutions may be more appropriate than others depending on the duration, timing, scale and locational characteristics of the identified need.

- **The assessment highlights that flexibility needs may be met through a combination of explicitly procured flexibility products and through more efficient market arrangements that enable flexible resources to respond to system needs.** It is not likely to be economic to meet all the identified needs through additional flexibility, and some residual renewable dispatch down is therefore expected to remain and may represent the efficient outcome, particularly where barriers to market participation of flexibility sources have been removed.
- The assessment demonstrates that flexibility solutions should not be considered as alternatives to traditional network reinforcement, but as complementary tools that can support more efficient network planning and operation. Depending on the nature, duration and certainty of the identified need, flexibility may defer or complement required grid reinforcement, while in most cases conventional network investment will remain necessary.
- A number of potential market design, regulatory and operational barriers to flexibility deployment were identified through the assessment. The assessment notes that while some of these identified barriers remain significant, progress is already being made in a number of areas through ongoing market, operational and digitalisation initiatives.
- **Effective coordination between the system operators will become increasingly important as flexibility markets and procurement arrangements develop.** The assessment highlights the importance of continued TSO-DSO engagement through joint planning, operational coordination, data sharing and the development of coordinated operating frameworks capable of supporting value and revenue stacking across local flexibility, system services and wholesale market participation. In particular, implementation of coordinated operating arrangements, including through development of the TSO-DSO Operating Model through the Joint System Operator Programme, is expected to play an important role in overcoming structural and administrative barriers that currently limit the ability of flexible demand and other flexibility providers to access the full value of flexibility services. Strong TSO-DSO coordination will therefore be essential to support efficient scaling of flexibility, maximise utilisation of flexible resources across the electricity system and ensure that interactions between transmission and distribution system needs are appropriately managed.
- As this is the first iteration of the National FNA, further development of the methodologies, modelling approaches, data sources and analytical approaches will be required in future assessments. In particular, the assessment identified a number of challenges associated with applying the ACER methodology using existing modelling frameworks and aligning European methodology requirements with SEM-specific operational arrangements and processes.

17. Next steps

This section outlines the next stages of work following completion of Ireland's first National Flexibility Needs Assessment. The CRU intends to continue engagement with EirGrid and ESB Networks following publication of this report to support the ongoing development of flexibility arrangements in Ireland, while also continuing to coordinate with the Utility Regulator on relevant SEM and all-island market developments.

The primary next step, in line with the requirements of Regulation (EU) 2019/943 (as amended by Regulation (EU) 2024/1747), is the requirement for Member States to set an indicative national objective for non-fossil flexibility in 2027. The CRU expects to continue working closely with EirGrid and ESB Networks during 2026 to further develop the supporting analysis and evidence base, and to support the Department of Climate, Energy and the Environment on the setting of the indicative national objective in 2027. The findings of this assessment, alongside further analysis and stakeholder engagement, are expected to inform this process.

The CRU will consider the findings of this report where relevant in future policy, regulatory, market and procurement-related decisions, including any future considerations of flexibility procurement frameworks. In doing so, the CRU will consider the full range of flexibility solutions and delivery approaches that could address or reduce the identified needs. **The flexibility needs identified in this report should not be interpreted as prescribing a preferred technology, commercial model, procurement route or policy outcome.**

The CRU also recognises the importance of understanding the underlying drivers of the identified flexibility needs and the most efficient means of responding to them. **Future work may therefore consider both how flexibility solutions can be deployed to meet the identified needs and how market, operational and network measures could reduce those needs in the first place**. This could include further examination of the drivers of renewable dispatch down and flexibility requirements, including the role of market arrangements, operational constraints, network limitations and potential existing market failures, as well as opportunities to improve market outcomes, operational efficiency and network utilisation. As renewable generation and electrified demand become increasingly central to the operation of the electricity system, future work may need to consider whether existing market and operational arrangements remain effective and how these frameworks may need to evolve to support greater demand elasticity, more active participation by flexible demand and renewable resources, and efficient responses to system needs and market signals. Such consideration could help inform the identification of effective, proportionate and cost-efficient responses to support Ireland's transition to a highly renewable electricity system.

EirGrid and ESB Networks are expected to consider the findings of this assessment in future network development planning, flexibility procurement activities and future flexibility pilot and market development work. In particular, the report highlights the importance of continuing to assess where identified needs are best addressed through flexibility solutions, traditional network reinforcement, or a combination of both approaches depending on the characteristics of the need identified.

The CRU, EirGrid and ESB Networks will also continue work to better understand and where appropriate address the key market design, regulatory and operational barriers identified through this assessment. This includes continued consideration of issues relating to market access, value stacking, operational coordination, procurement arrangements and participation by flexibility providers across multiple markets and services. The CRU notes the views received in response to the Information Paper published in April 2026. The CRU welcomes further comments and views from industry in response to this Assessment, and as the CRU considers its implications.

A number of related policy, market and regulatory workstreams are already ongoing and are expected to influence the future development of flexibility arrangements in Ireland. This includes ongoing work relating to network tariff structures, capacity market arrangements, flexibility procurement (LDES and Demand Response) and TSO-DSO coordination frameworks. These developments are expected to contribute to addressing some of the barriers identified in this report, including barriers associated with revenue stacking, market participation and investment signals for flexibility.

The CRU also intends to work with EirGrid, ESB Networks and the Utility Regulator to identify potential improvements for future iterations of the FNA process, including consideration of modelling approaches, scenario selection, data requirements, all-island coordination and alignment between the ACER methodology and SEM operational arrangements. Feedback arising from Ireland's experience implementing the first FNA will be considered as part of future engagement with ACER and wider European discussions on the evolution of the methodology.

The FNA is expected to become an iterative and evolving process, with Regulation (EU) 2019/943 (as amended by Regulation (EU) 2024/1747) requiring Member States to complete and publish an updated Flexibility Needs Assessment at least every two years. Following publication of this first National FNA in 2026, the CRU expects to continue working with EirGrid and ESB Networks on the development of future assessment cycles, with the next iteration expected to commence during 2027 ahead of publication of an updated assessment in 2028. Future iterations of the FNA are expected to consider longer-term flexibility requirements, additional target years, evolving system and network needs, and further refinements to modelling approaches and data sources as Ireland's electricity system continues to decarbonise and electrify.

Part F: Appendix

Appendix A – System Level Analysis - evidence for ACER Methodology Articles not completed

Article 8(10): *In case of positive uncovered RES integration needs, the TSOs shall analyse the benefit of adding new flexibility resources to the system for the target years.*

- This is not applicable as there are no uncovered RES integration flexibility needs according to how this is defined in the FNA methodology. However, a number of studies were carried out separately to meet the needs of Article 16(6) which provide information that can help with understanding these points, please see Section 8.

Article 8(11): *The TSOs shall quantify additional flexibility resources required to meet the RES integration target.*

- This is not applicable as there are no uncovered RES integration needs according to how this is defined in the FNA methodology.

Article 8(12): *The TSOs shall assess the impact of additional flexibility resources on the RES integration pursuant to paragraphs (6) to (11), either by running an economic dispatch simulation pursuant to Article 7(3)(b), or by reflecting the new flexibility resources in the residual load time series resulting from economic dispatch results pursuant to Article 7(3)(a) and taking into account the contribution of flexible resources and interconnections.*

- This is not applicable as there are no uncovered RES integration flexibility needs according to how this is defined in the FNA methodology. However, in the additional studies that were carried out separately to meet the needs of Article 16(6) (please see Section 48), these were based on running economic dispatch simulations including the additional flexibility resources in the way considered in this Article.

Article 8(14): *To produce fine-tuned results pursuant to Article 14, the TSOs shall repeat the relevant steps described in paragraphs (10) to (12) reflecting the additional RES curtailment and unavailability of flexible resources within either the separate economic dispatch or the ERAA's / NRAA's economic dispatch results*

- This is not applicable as there are no uncovered RES integration flexibility needs according to how this is defined in the FNA methodology.

Article 8(15) & 8(16): *Unavailability of flexible resources is applied in the form of derating factor to the flexible resources considered in the economic dispatch pursuant to Article 7(3), based on the estimation resulting from the application of Article 13 and correlating information via time periods (hour and day of the year) or system operation conditions (renewable and load conditions). The derating factor shall be allocated to hours in which the network could face constraints. The derating of flexible resources pursuant to paragraph (15) shall be reported to the designated authority or entity.*

- This is not applicable as the threshold testing as part of Article 13 and Article 14 for the relevant unavailability aspects (which are restricted to the DSO) show that it is below the threshold and therefore does not need to be taken into account in fine-tuning, please see Section 2.3 for more details.

Article 8(17): *Whenever accounting for the contribution of flexible resources considered in the inputs of the economic dispatch pursuant to Article 7(3), and whenever additional RES curtailment has been added due to ramping or short-term needs pursuant to paragraph (3), TSOs shall account for flexible resources that were already used in the computation of the flexibility gap for ramping and/or short-term needs.*

- This is not applicable as ramping and short-term needs have been included in the model inputs and thus do not need to be accounted for separately within post-processing.

Article 12(5): *The TSOs shall carry out a cost-benefit analysis to justify the use of flexible solutions as an alternative to grid expansion. In doing so, they shall provide to the designated authority or entity, and where an entity is designated also to the NRA, a description of the method and the calculations they used to make this comparison.*

- In the scope document agreed by EirGrid and CRU in November 2025, EirGrid stated that a specific cost benefit analysis under Article 12(5) would not be carried out as it would be anticipated that there would be a negative cost-benefit situation in considering flexible alternatives to network development.
- Version 1.1 of the Shaping Our Electricity Future roadmap published by EirGrid (link here), the proposed candidate projects were studied and analysed in such a way to "*determine what additional projects are potentially needed to further increase the capability of the transmission system and ensure the Renewable Ambition is delivered*", to help "*meet the Renewable Ambition by adding flexibility to respond to the variability of renewable generation but that do not add capacity to the network.*", and are "*designed to maximise the use of the existing transmission network, therefore minimising the need for new infrastructure*", using the well-established Transmission System Security and Planning Standards (TSSPS). Based on the comprehensive transmission network analysis, list of candidate reinforcements to help manage, and analysis of additional flexible resources to manage power-system-wide issues with surplus renewables to help reach the RES integration targets, the analysis determined that it could be possible for the level of constraints of renewables to be of the order of 0.6%, approximately 352GWh, in the year 2030. This analysis was focussed on what would be required to accommodate the level of renewables required from the Climate Action Plan to achieve the renewable ambition, not what is forecasted as an expected level of constraint. This list of candidate projects was the basis for all ongoing transmission network development plans, which are updated and assessed against delivery over time through the Network Delivery Portfolio publications during PR5 (https://www.eirgrid.ie/grid/grid-reports-and-planning/network-delivery-portfolio) and now in PR6 through the Transmission Infrastructure Delivery (TID) publications (https://www.eirgrid.ie/grid/grid-reports-and-planning/transmission-infrastructure-delivery-tid-update); The latest network development plans feed into the assumptions for the ECP constraint forecast analysis modelling assumptions. The continued

development of the network to the existing plan is required to reduce network constraints and associated costs. Therefore, a detailed Cost Benefit Analysis on this topic as considered under Article 12(5) of the ACER Methodology was not conducted.

Article 16(7): *The TSOs shall assist with further analysis of the assessment of the capability of the different sources of flexibility to meet uncovered upward needs, quantified pursuant to Articles 9, 10 and 12. In particular, the TSOs shall provide: a. Analysis of the technical capability of the different sources of flexibility (e.g., additional flexibility resources - including at local level where relevant, additional reserve capacity, or further participation to balancing) to reduce the uncovered needs. The TSOs shall account for the technical characteristics, sub-indicators identified in paragraph (5), and cost-efficiency. b. Analysis to verify possible overlaps with the adequacy findings of ERAA or NRAA, starting with the results of the scenarios compliant with Article 3(5)(a) of the ERAA methodology. When analysing the uncovered upward needs quantified pursuant to Articles 9 and 10, the TSOs shall consider reliability standards for the bidding zones, where such standard is defined.*

- For Article 16(7), there are no uncovered upward needs for the relevant aspects of this article from the FNA model, so no further work can be carried out on this aspect.

Article 16(8): *As short-term needs are covered by the FRR capacity in line with Article 157 of Commission Regulation (EU) 2017/1485 establishing a guideline on electricity transmission system operation, the TSOs shall provide an analysis on how uncovered short-term flexibility needs quantified in Article 10 will first be met using additional reserve capacity or with further participation to balancing.*

- Article 16(8) is not relevant in the context of the SEM. Since all resources participating in the wholesale electricity markets in the Single Electricity Market (SEM) are required, under the central dispatching approach, to be registered in the balancing market and provide their full availability to be dispatched up or down in this balancing market, there is no ability to carry out a separate analysis to consider this impact discussed in Article 16(8). Also, as outlined in Section 5.3, there are no uncovered short term flexibility needs.

Article 16(9): *For the identified transmission network needs quantified pursuant to Article 12, the TSOs shall provide an analysis of the capability of grid reinforcements already identified by the most recent published TYNDP or a national development plan to cover these needs.*

- For Article 16(9), the national development plan grid reinforcements are already contained within the ECP model so the baseline constraint results from Article 12 include this, no further analysis can be carried out.

Appendix B – System Level Needs – additional data and results

Appendix B.1 Article 8(1), 8(2), 8(3)

Figure 70: RES generation curtailment time series, hourly percentage throughout the year, 2028, WS4 – Article 8(1)

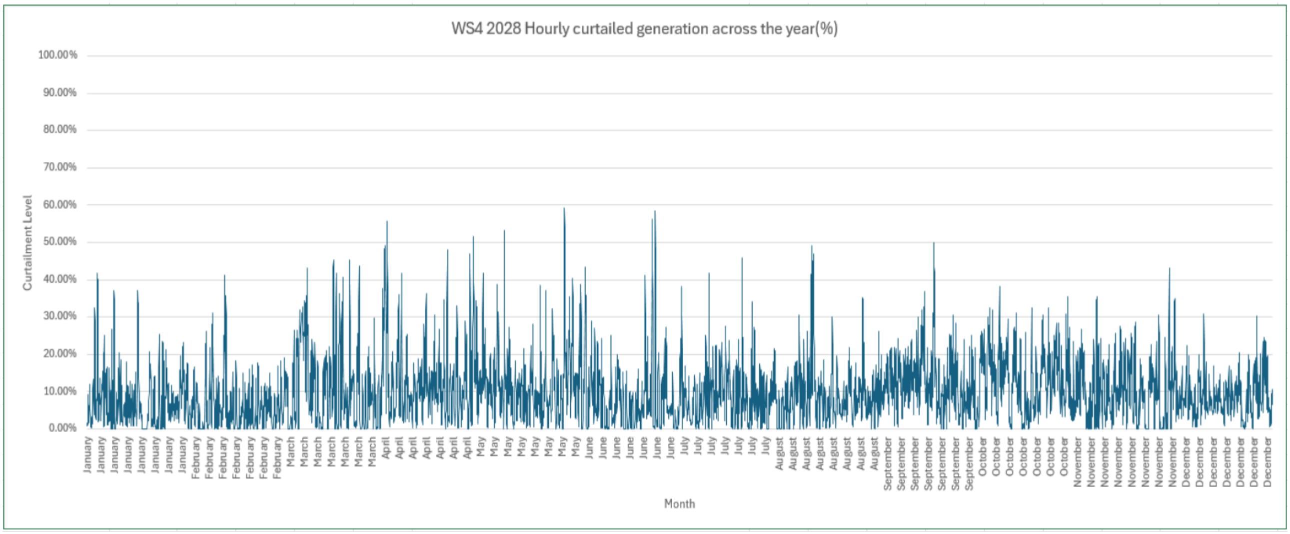


Figure 71: RES generation curtailment time series, hourly percentage throughout the year, 2030, WS4 – Article 8(1)

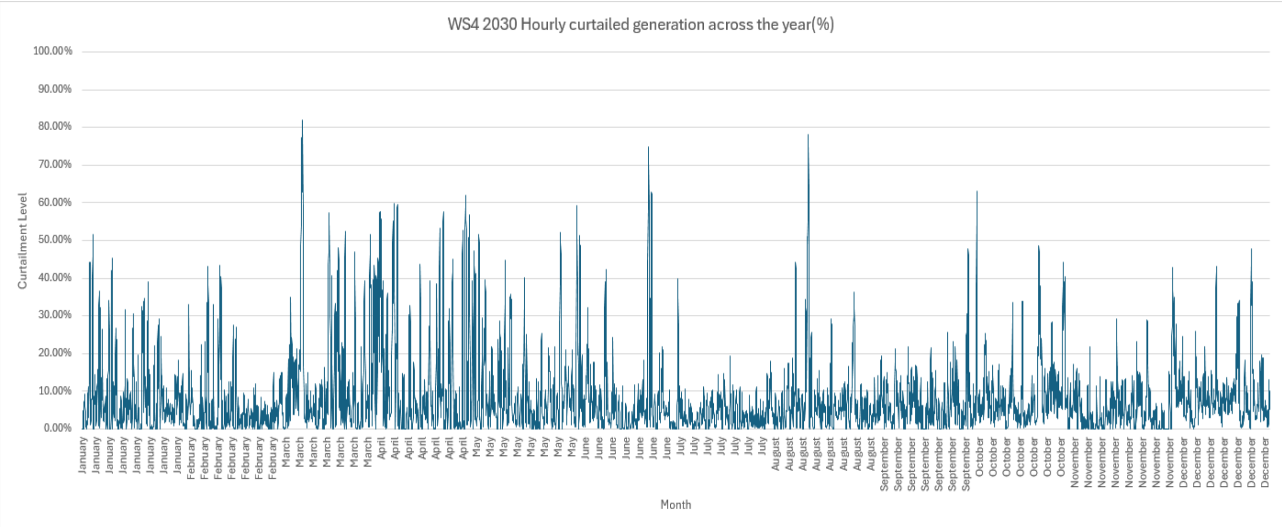


Figure 72: RES generation curtailment time series, hourly percentage throughout the year, 2028, WS34 – Article 8(1)

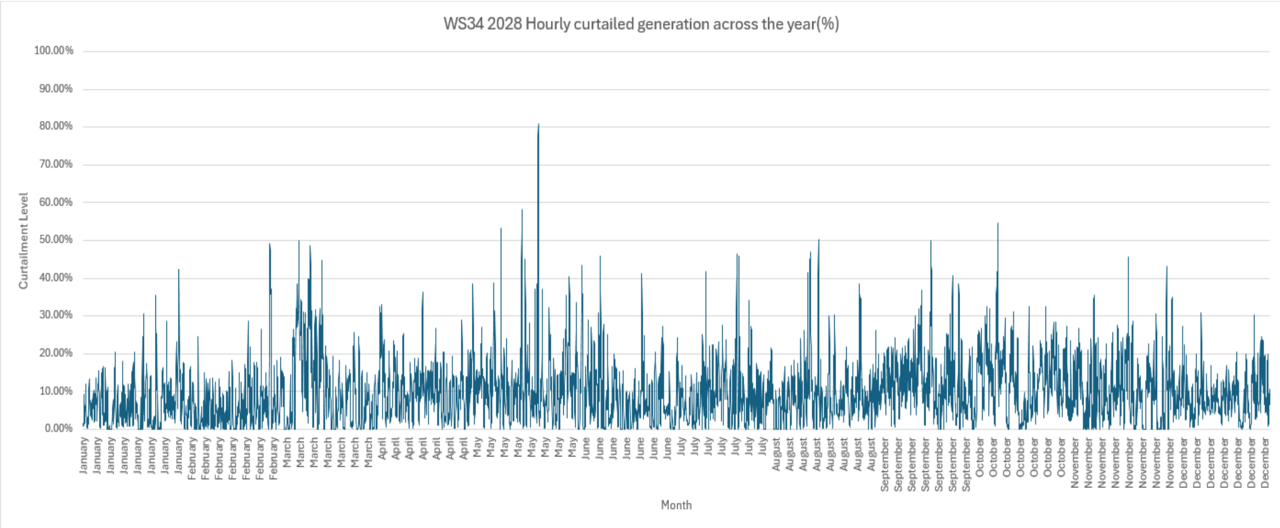
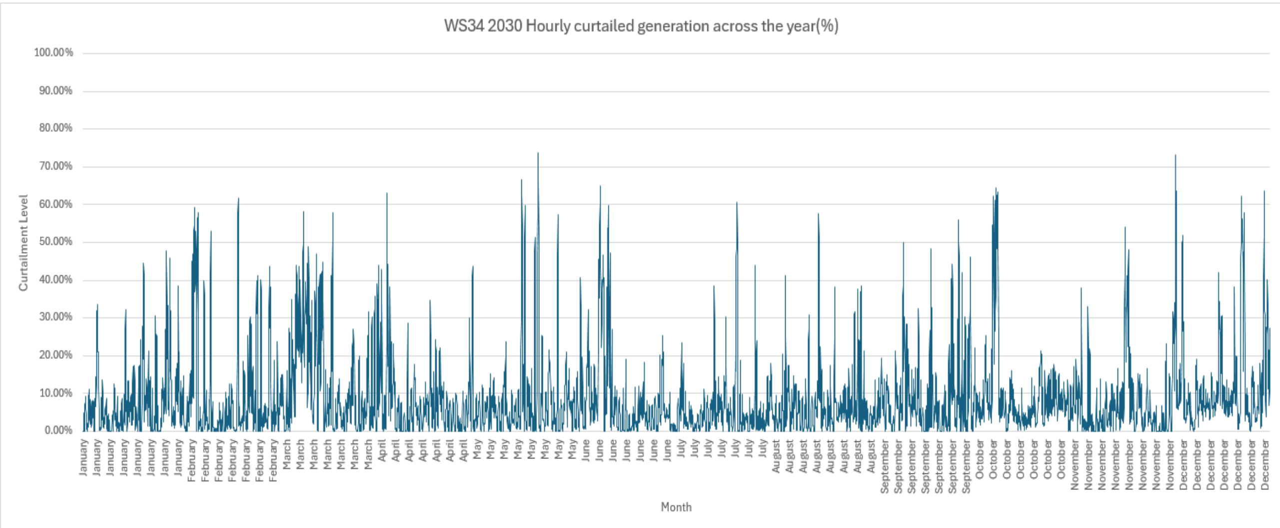


Figure 73: RES generation curtailment time series, hourly percentage throughout the year, 2030, WS34 – Article 8(1)



Appendix B.2 Article 8(4)

Appendix B.2.1 Article 8(4)(a) Average, max, min

Figure 74: Weekly, monthly and annual curtailment generation (average, maximum and minimum values), 2028, WS4 – Article 8(4)(a)

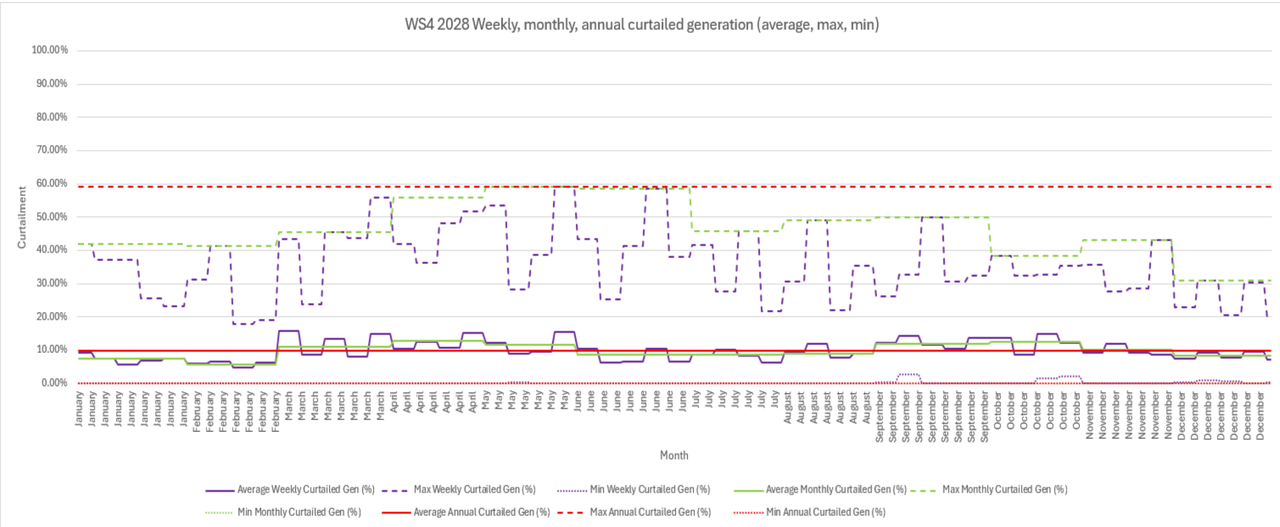


Figure 75: Weekly, monthly and annual curtailment generation (average, maximum and minimum values), 2030, WS4 – Article 8(4)(a)

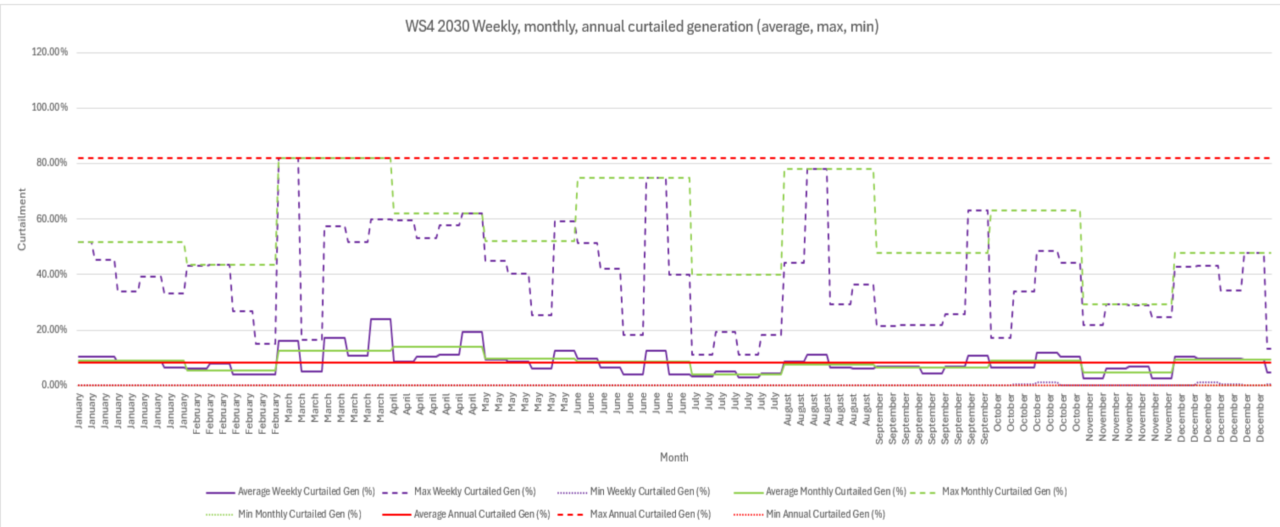


Figure 76: Weekly, monthly and annual curtailment generation (average, maximum and minimum values), 2028, WS34 – Article 8(4)(a)

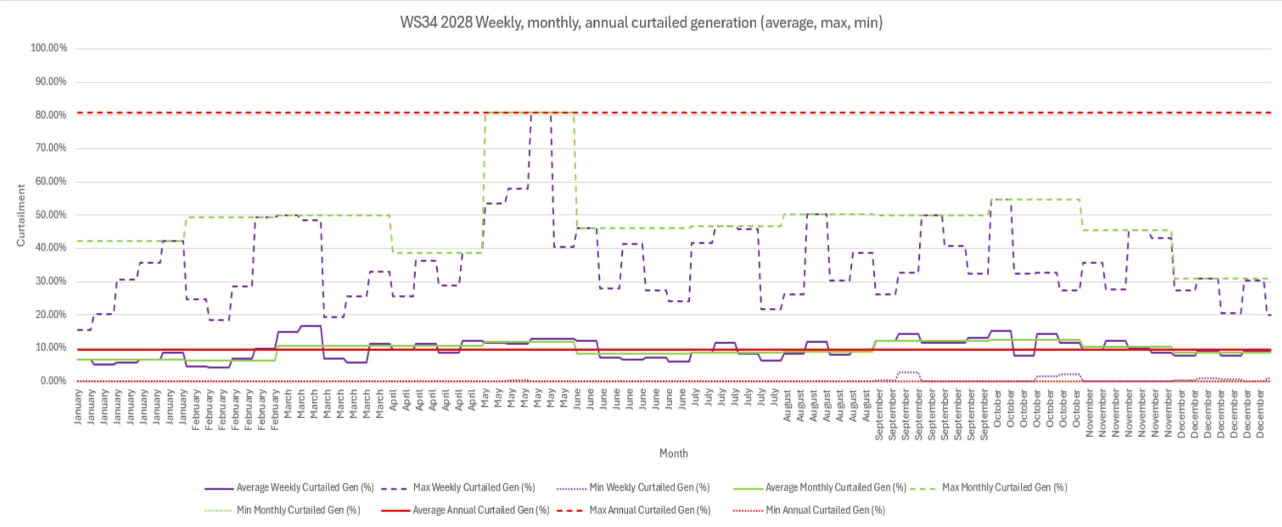
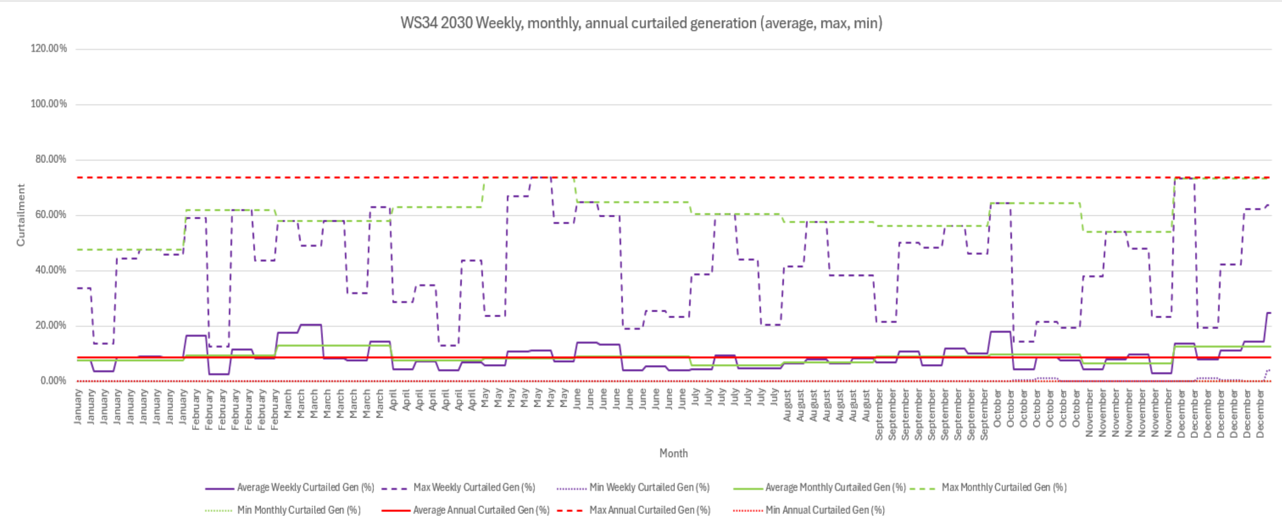


Figure 77: Weekly, monthly and annual curtailment generation (average, maximum and minimum values), 2030, WS34 – Article 8(4)(a)



Appendix B.2.2 Article 8(4)(b) Probability distribution

Figure 78: Hourly curtailment distribution chart, 2028, WS4 - Article 8(4)(b)

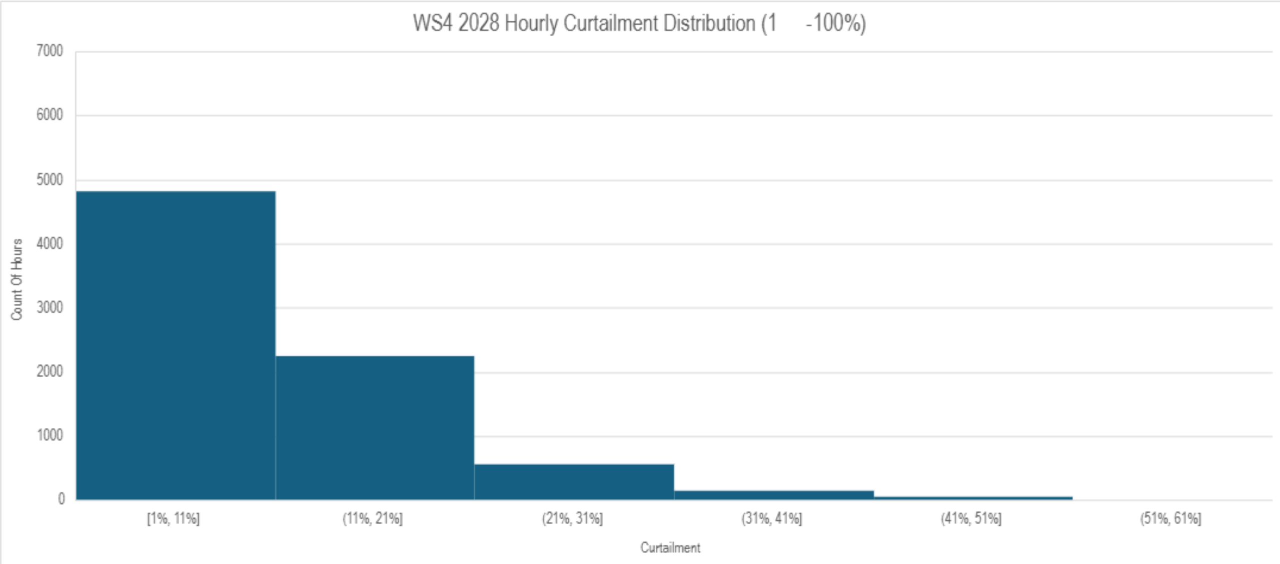


Figure 79: Hourly curtailment distribution chart, 2028, WS4 - Article 8(4)(b)

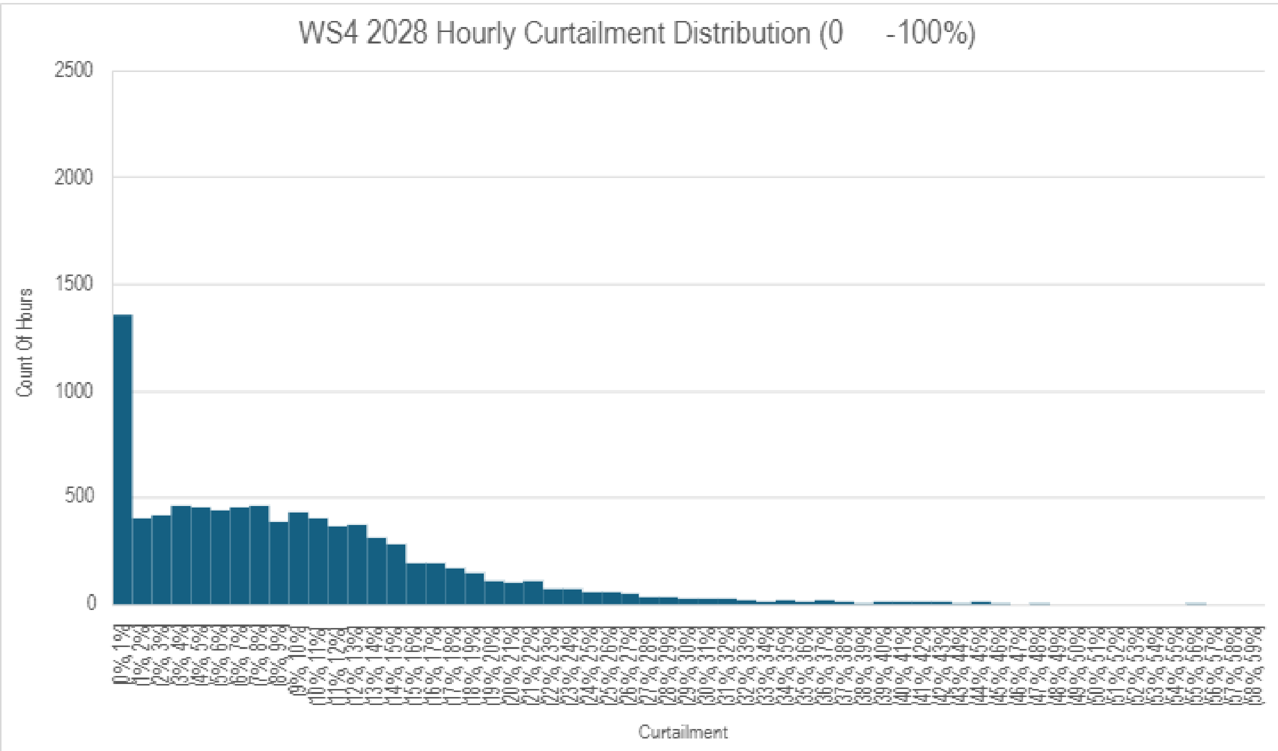


Figure 80: Hourly curtailment distribution chart, 2030, WS4 - Article 8(4)(b)

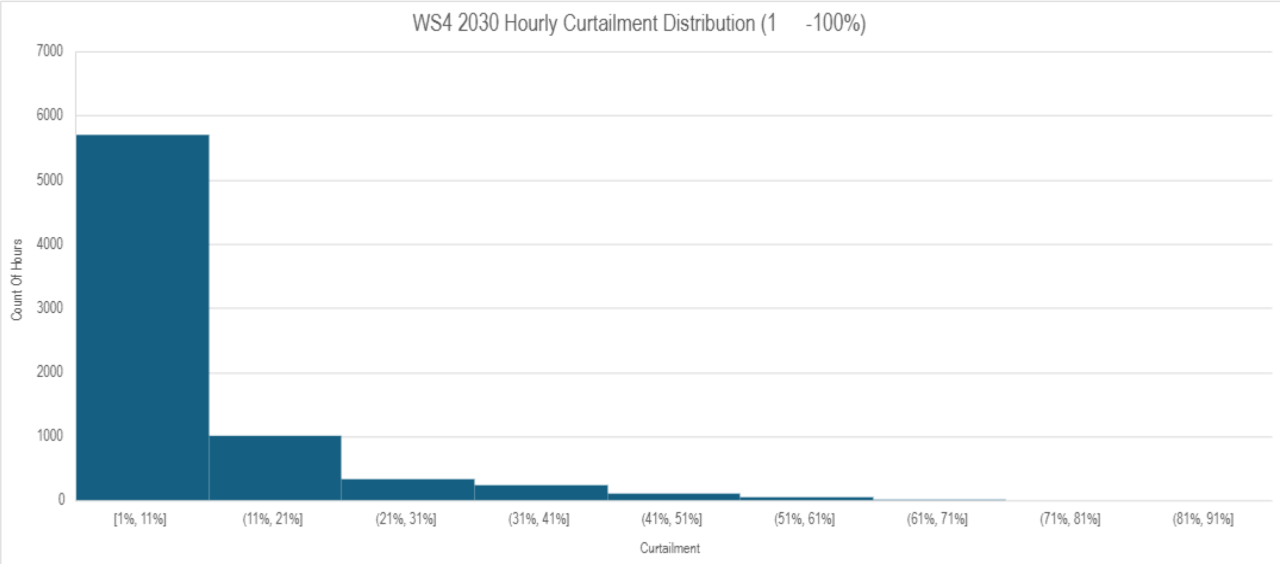


Figure 81: Hourly curtailment distribution chart, 2030, WS4 - Article 8(4)(b)

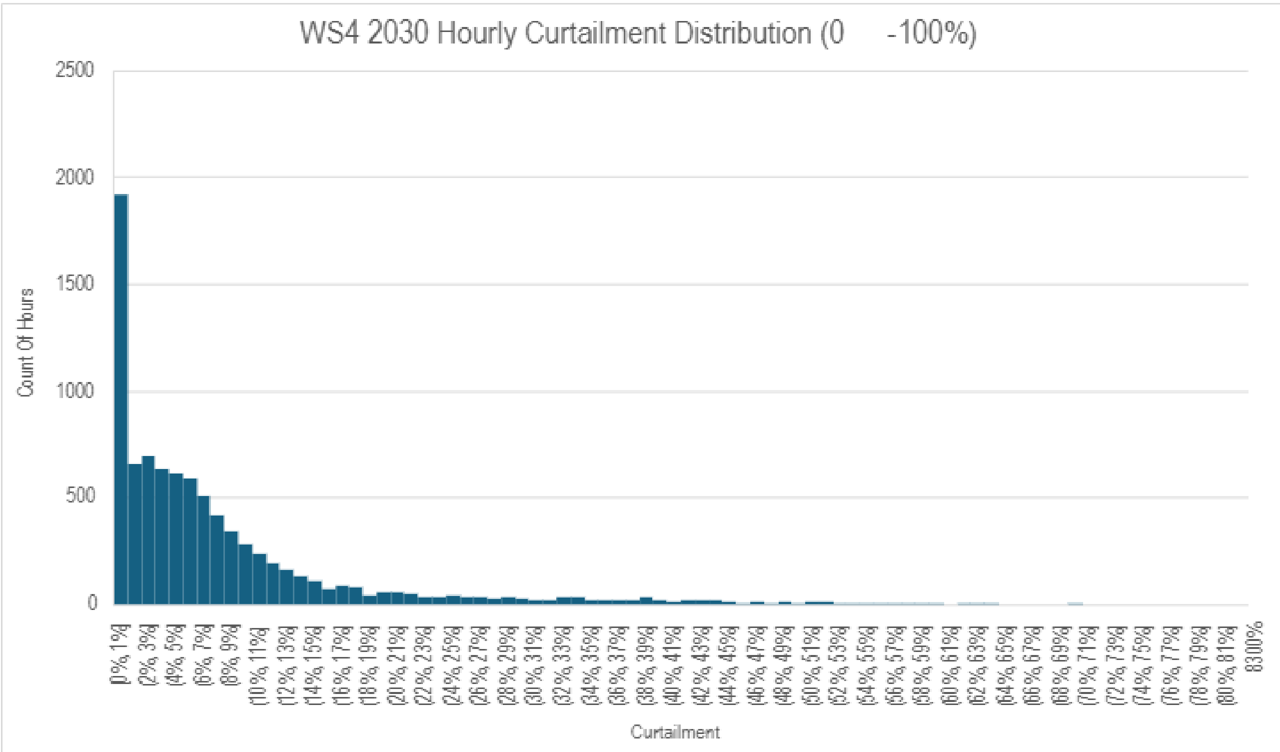


Figure 82: Hourly curtailment distribution chart, 2028, WS34 - Article 8(4)(b)

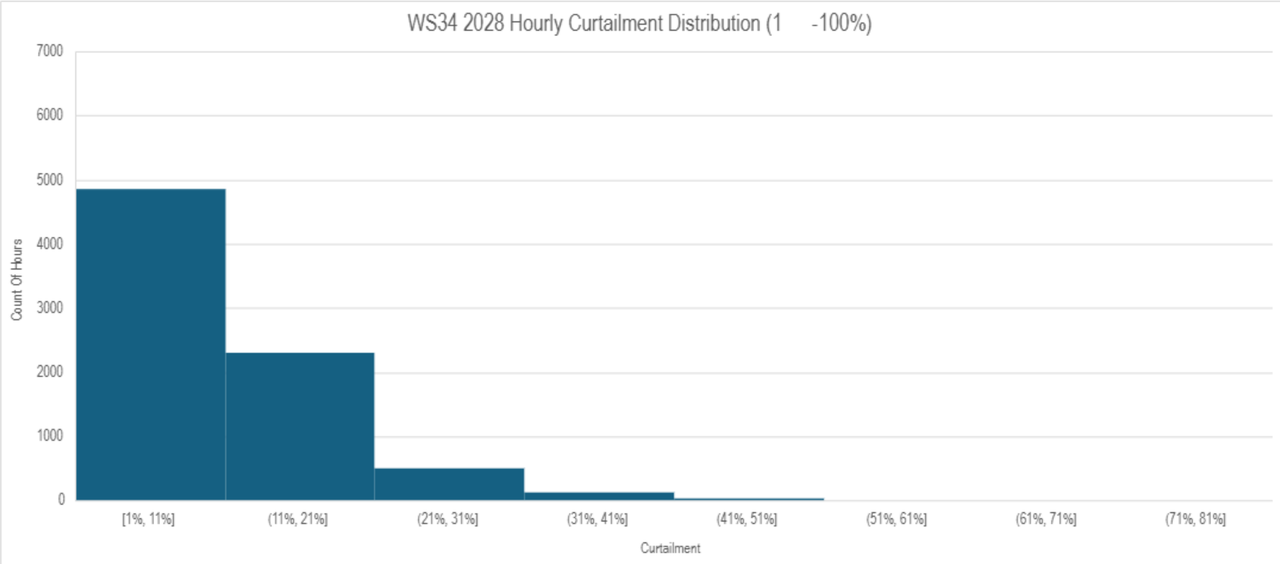


Figure 83: Hourly curtailment distribution chart, 2028, WS34 - Article 8(4)(b)

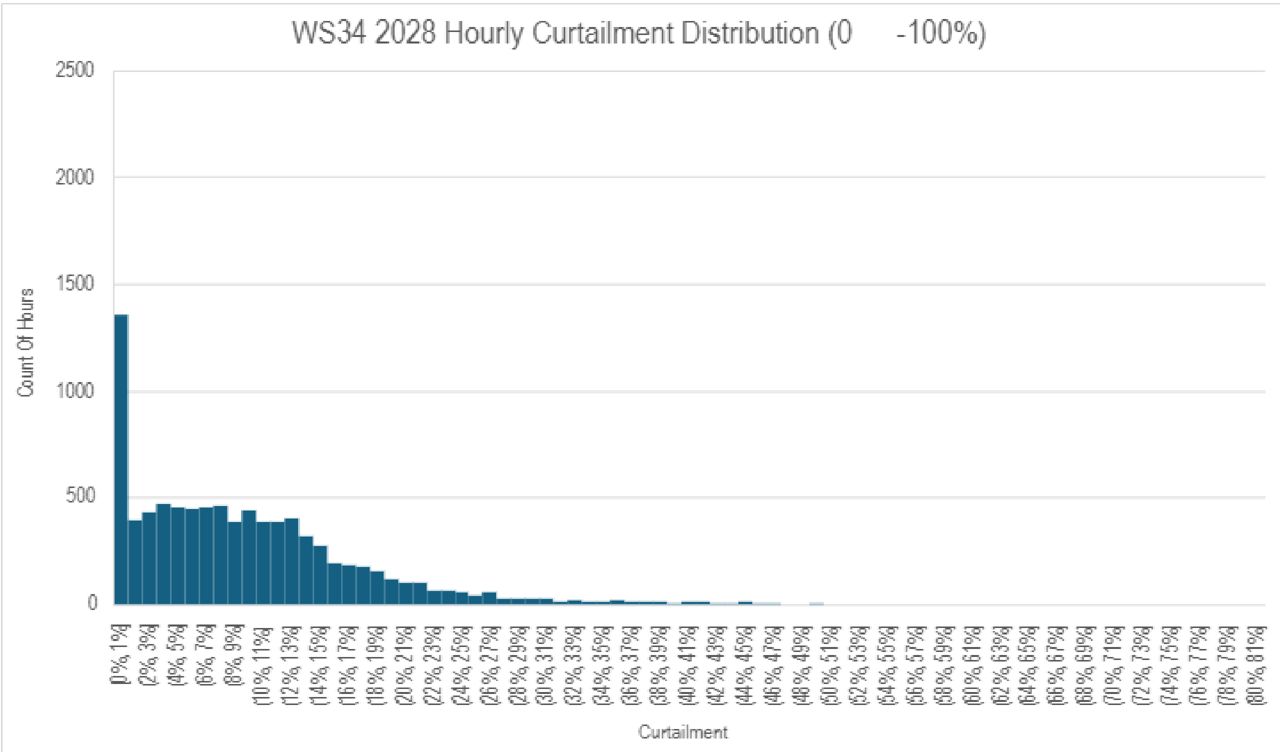


Figure 84: Hourly curtailment distribution chart, 2030, WS34 - Article 8(4)(b)

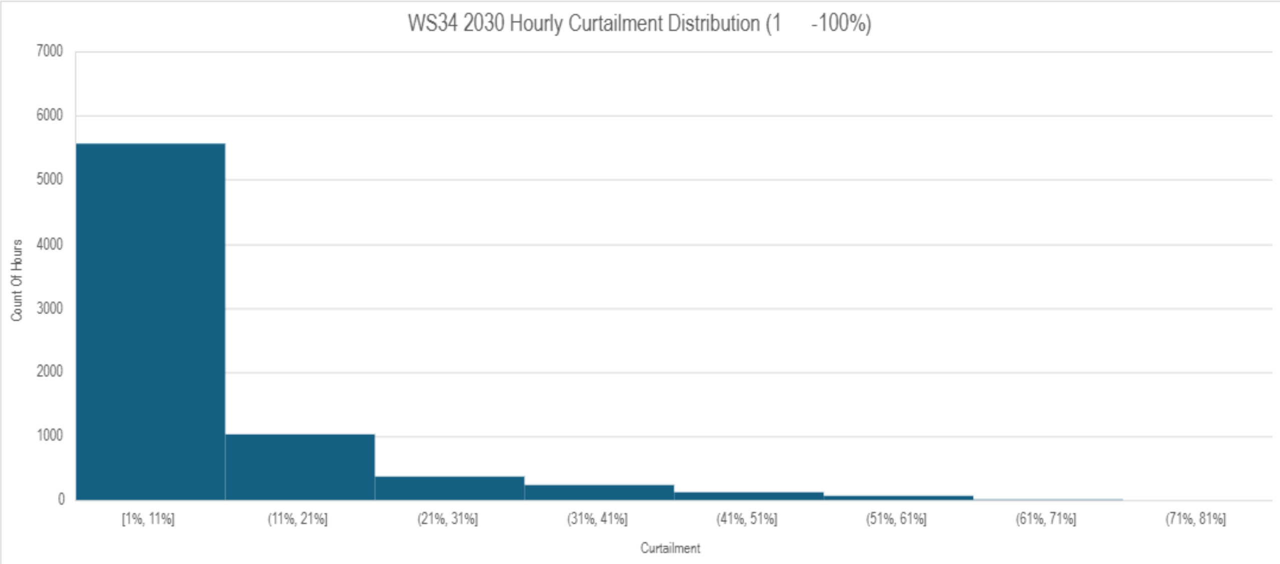


Figure 85: Hourly curtailment distribution chart, 2030, WS34 - Article 8(4)(b)

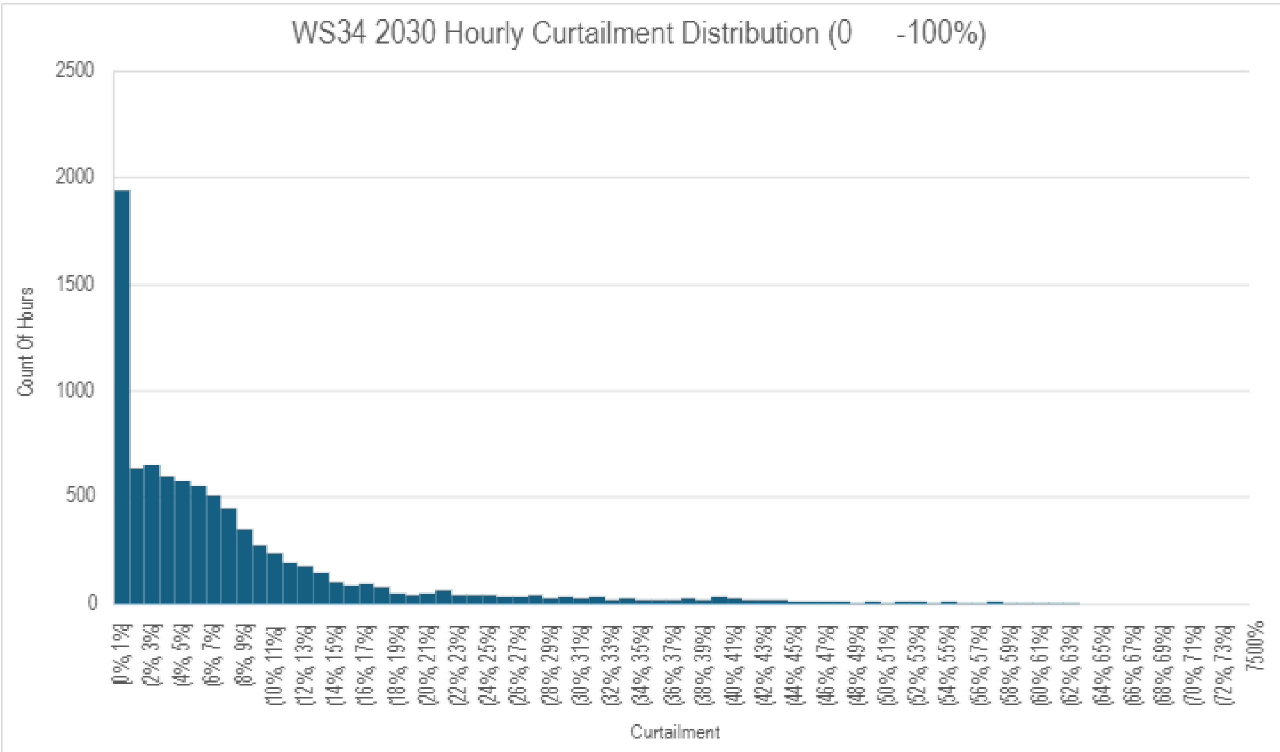


Figure 86: Daily average curtailment distribution, 2028, WS4 - Article 8(4)(b)

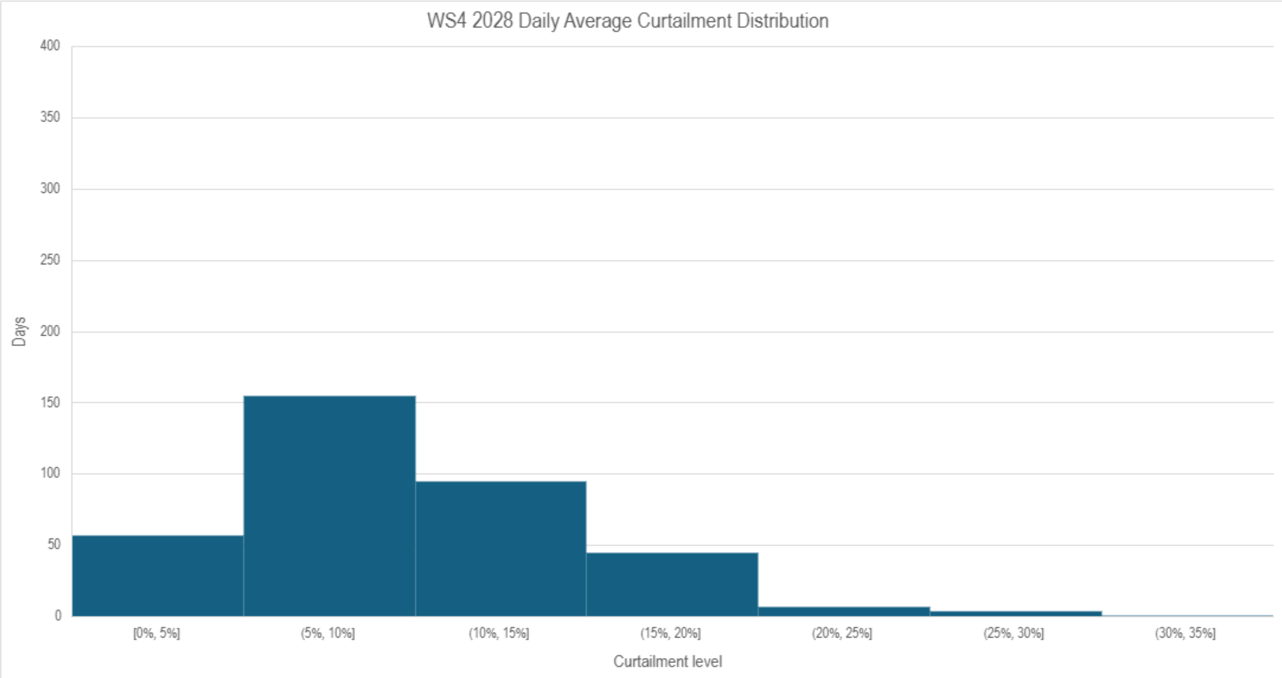


Figure 87: Daily average curtailment distribution, 2030, WS4 - Article 8(4)(b)

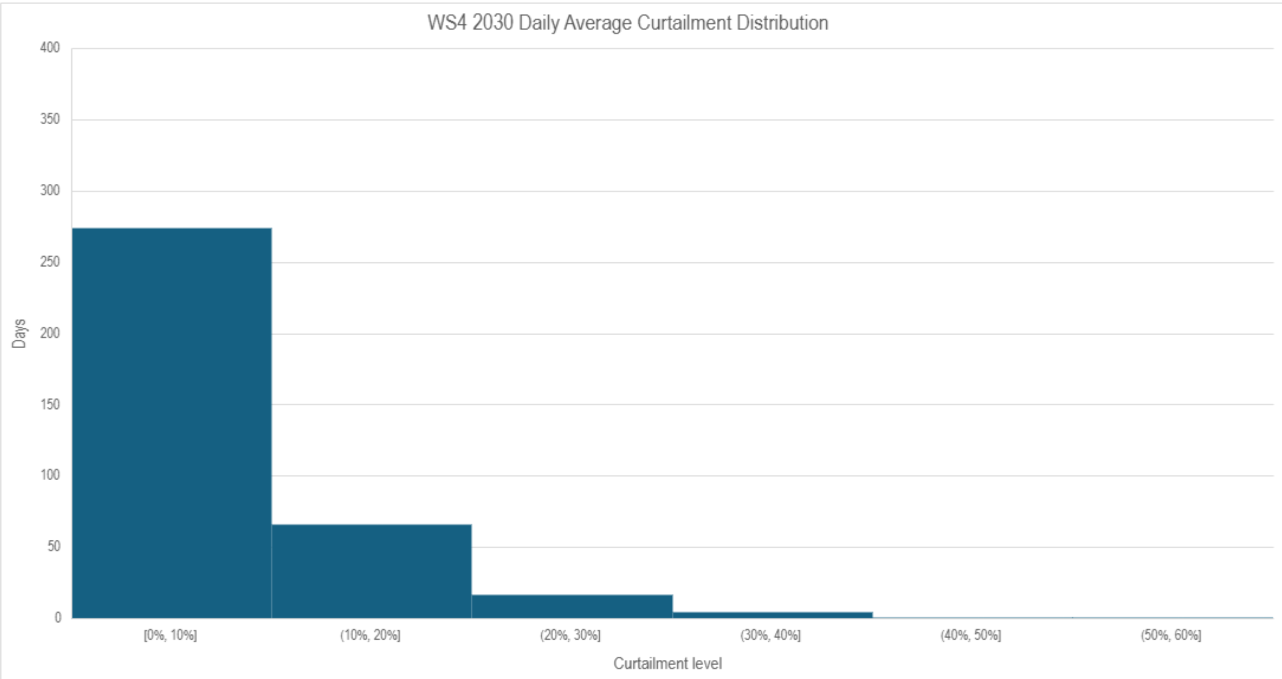


Figure 88: Daily average curtailment distribution, 2028, WS34 - Article 8(4)(b)

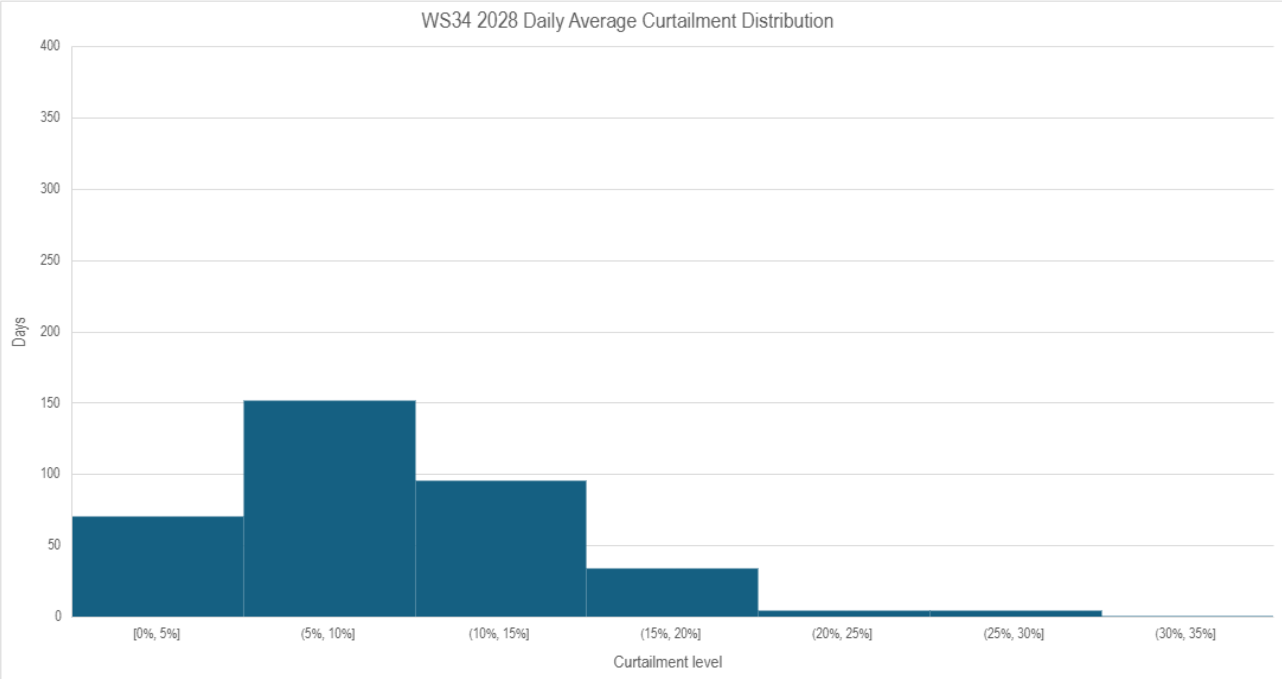


Figure 89: Daily average curtailment distribution, 2030, WS34 - Article 8(4)(b)

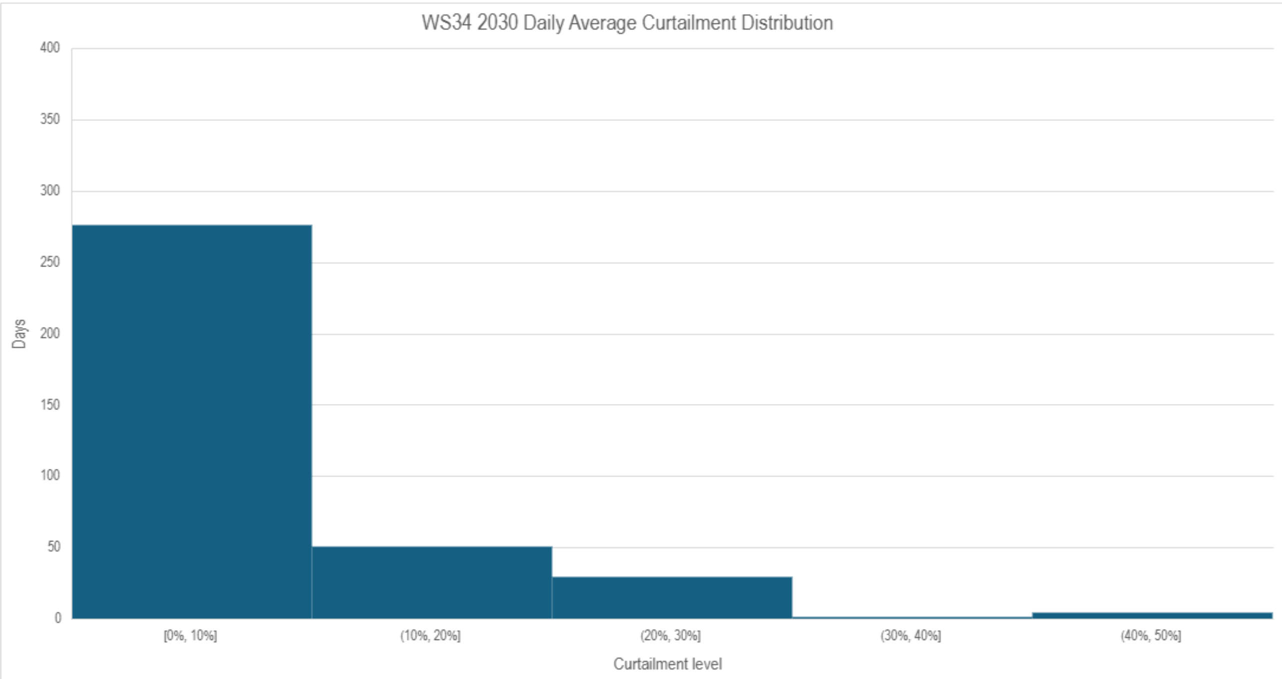


Figure 90: Weekly average curtailment distribution, 2028, WS4 - Article 8(4)(b)

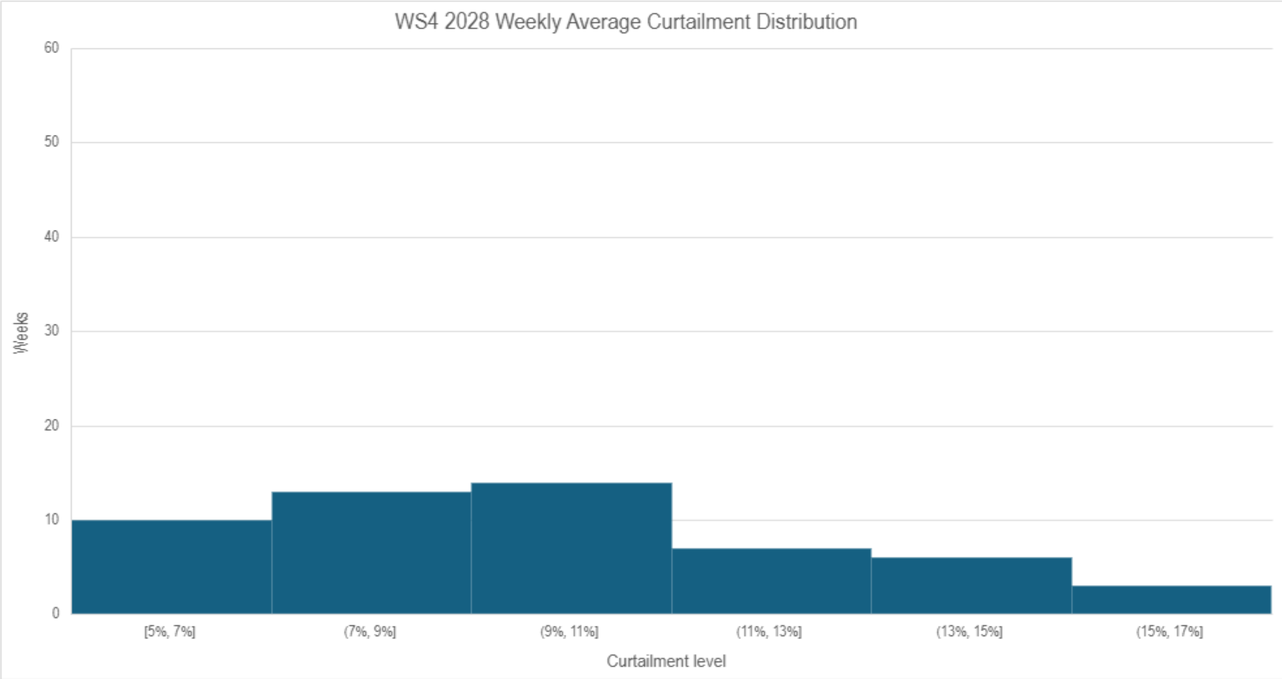


Figure 91: Weekly average curtailment distribution, 2030, WS4 - Article 8(4)(b)

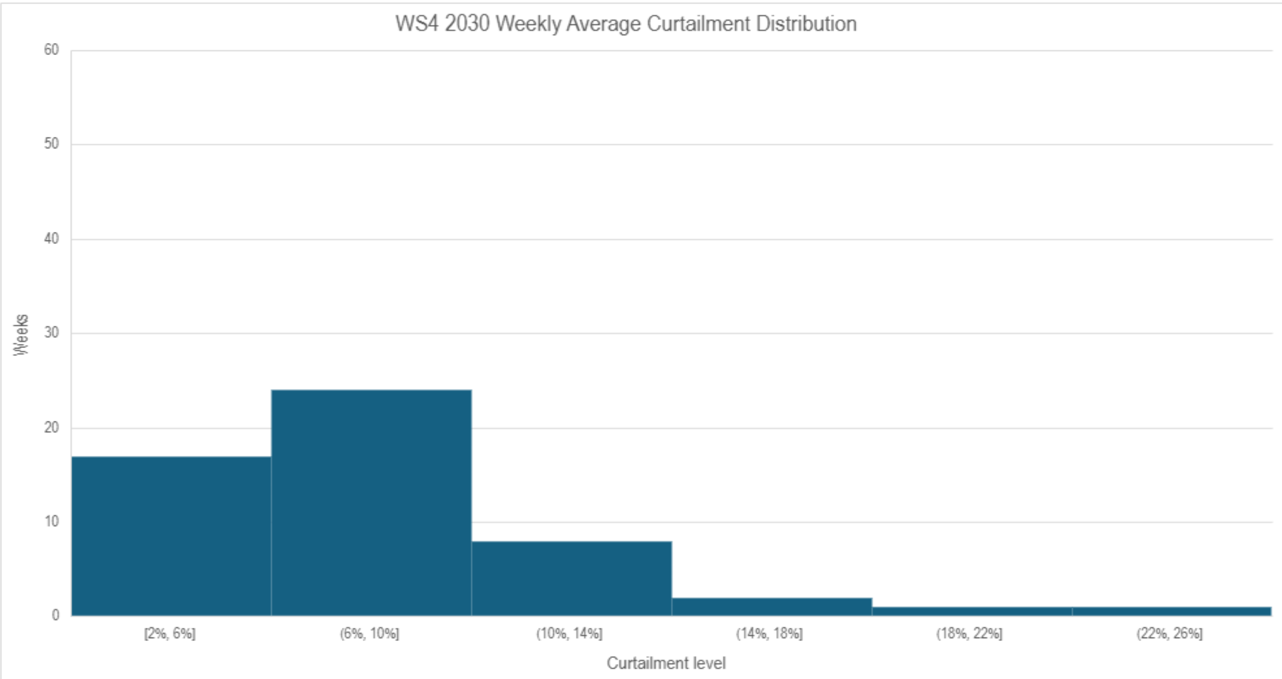


Figure 92: Weekly average curtailment distribution, 2028, WS34 - Article 8(4)(b)

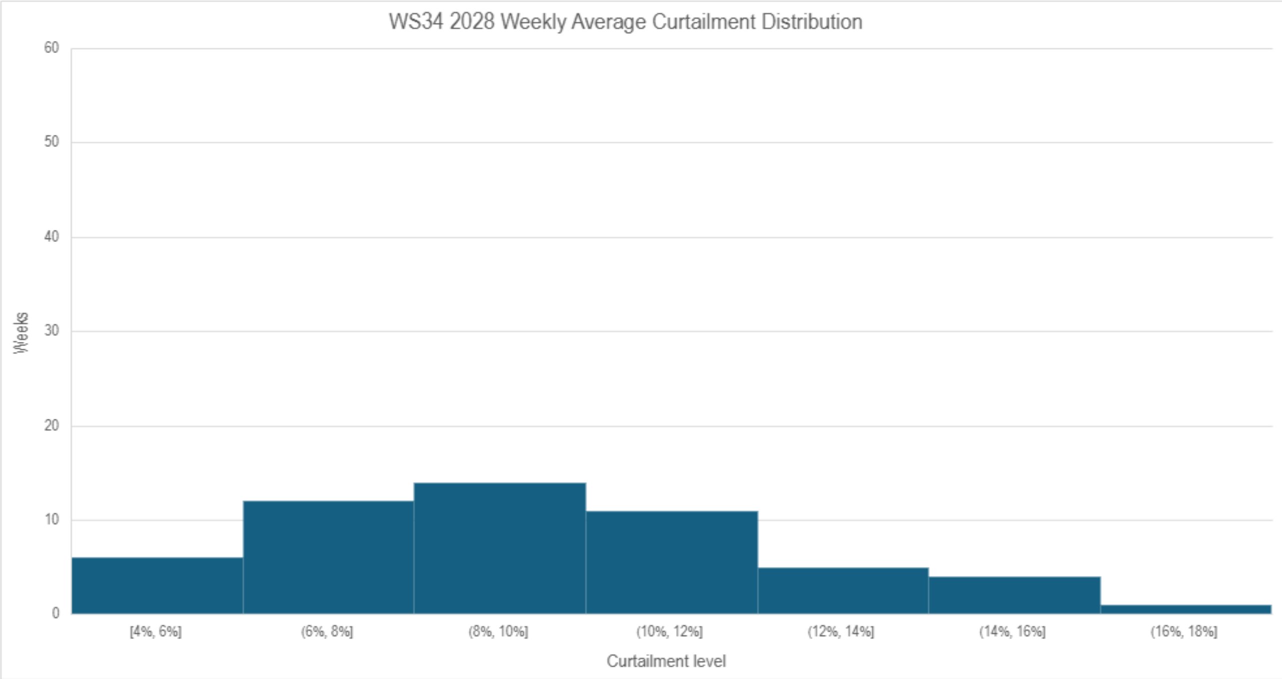


Figure 93: Weekly average curtailment distribution, 2030, WS34 - Article 8(4)(b)

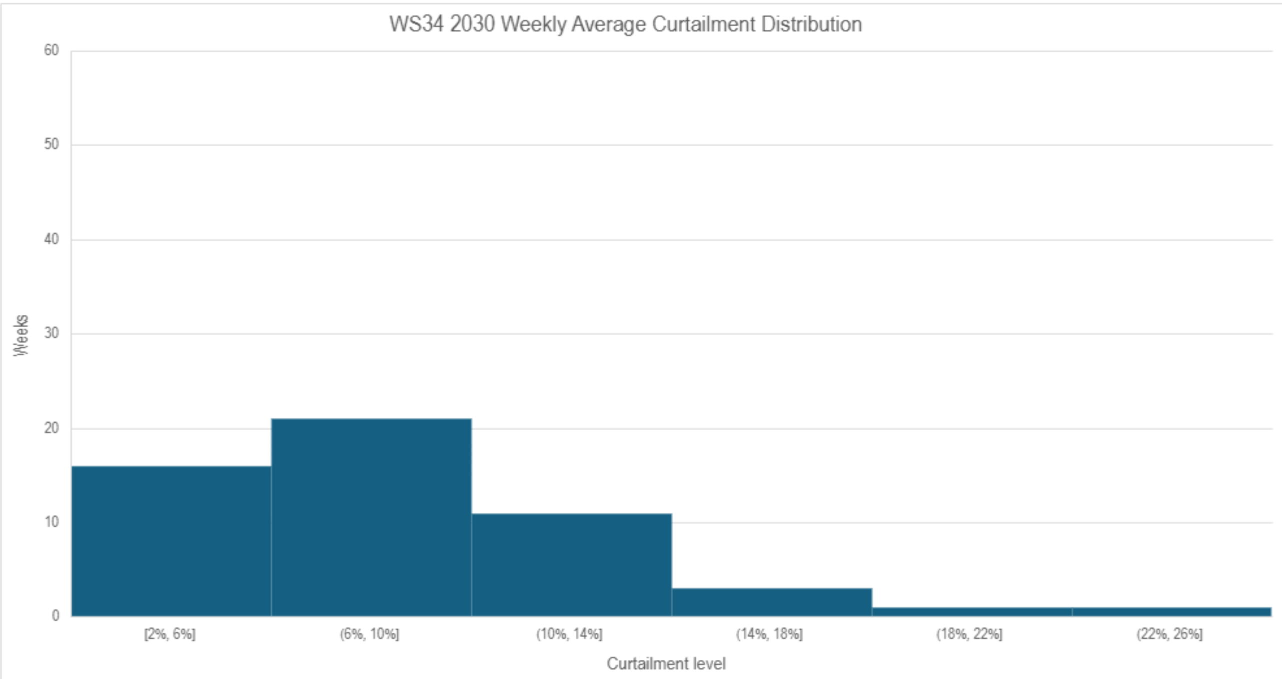


Figure 94: Monthly average curtailment distribution, 2028, WS4 - Article 8(4)(b)

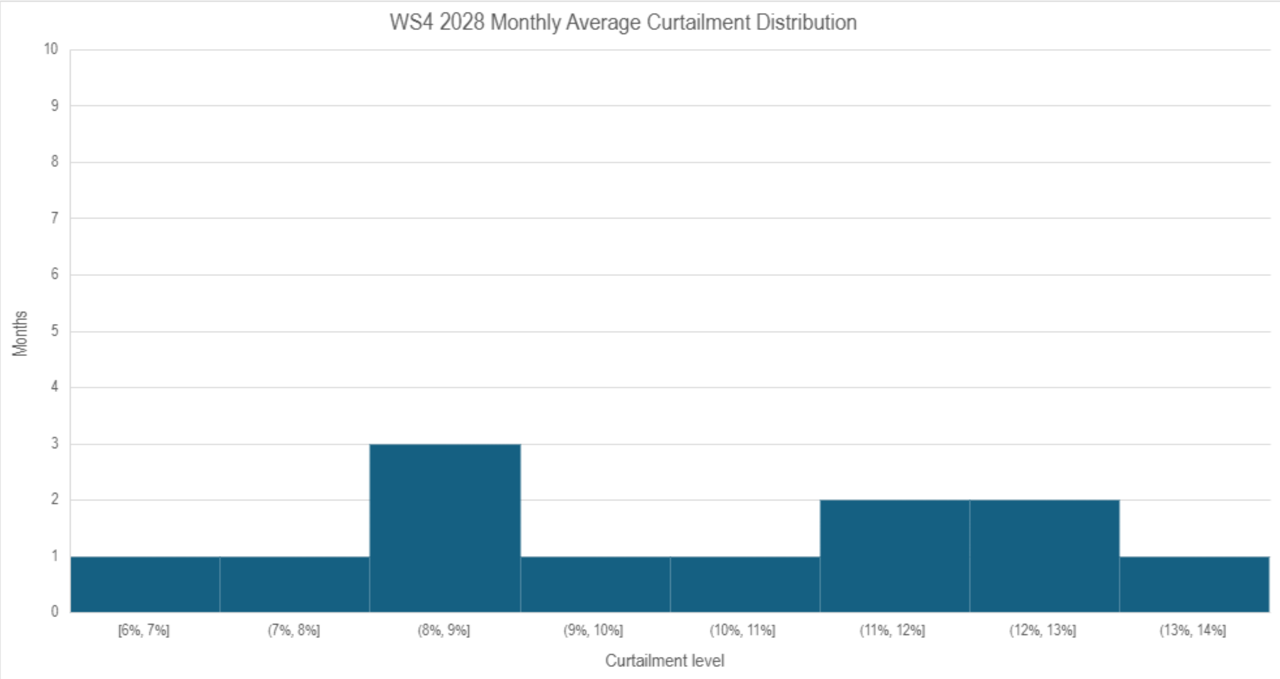


Figure 95: Monthly average curtailment distribution, 2030, WS4 - Article 8(4)(b)

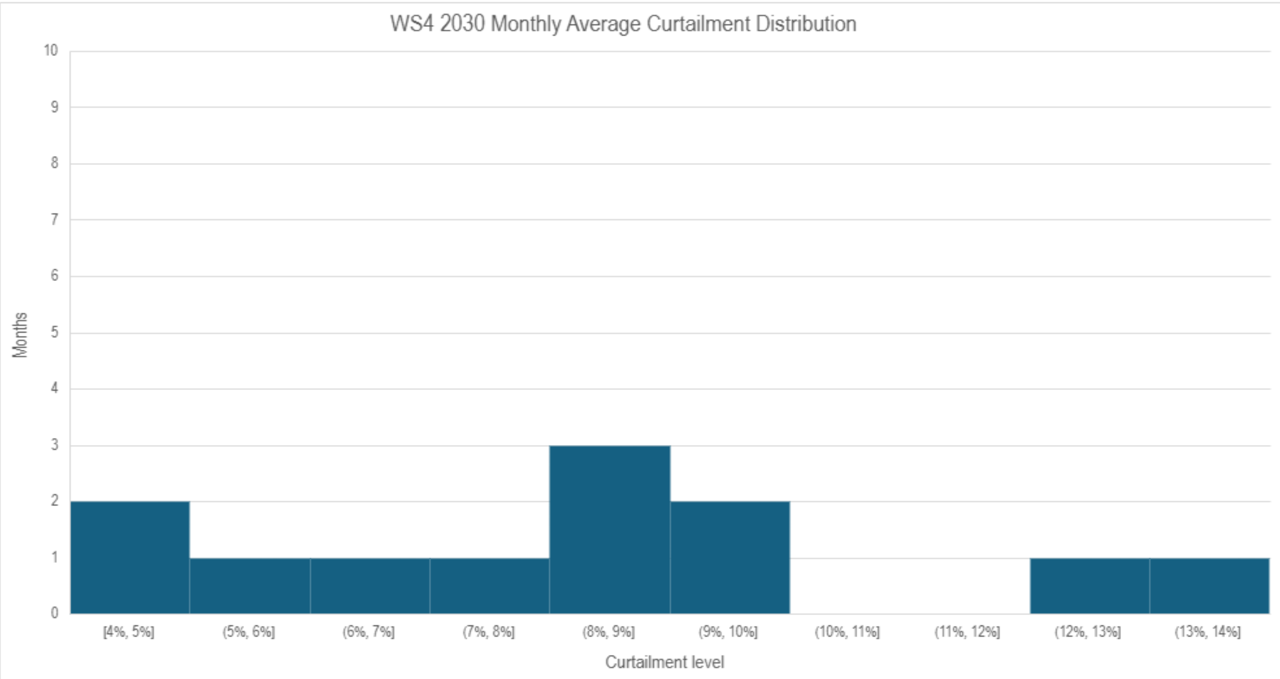


Figure 96: Monthly average curtailment distribution, 2028, WS34 - Article 8(4)(b)

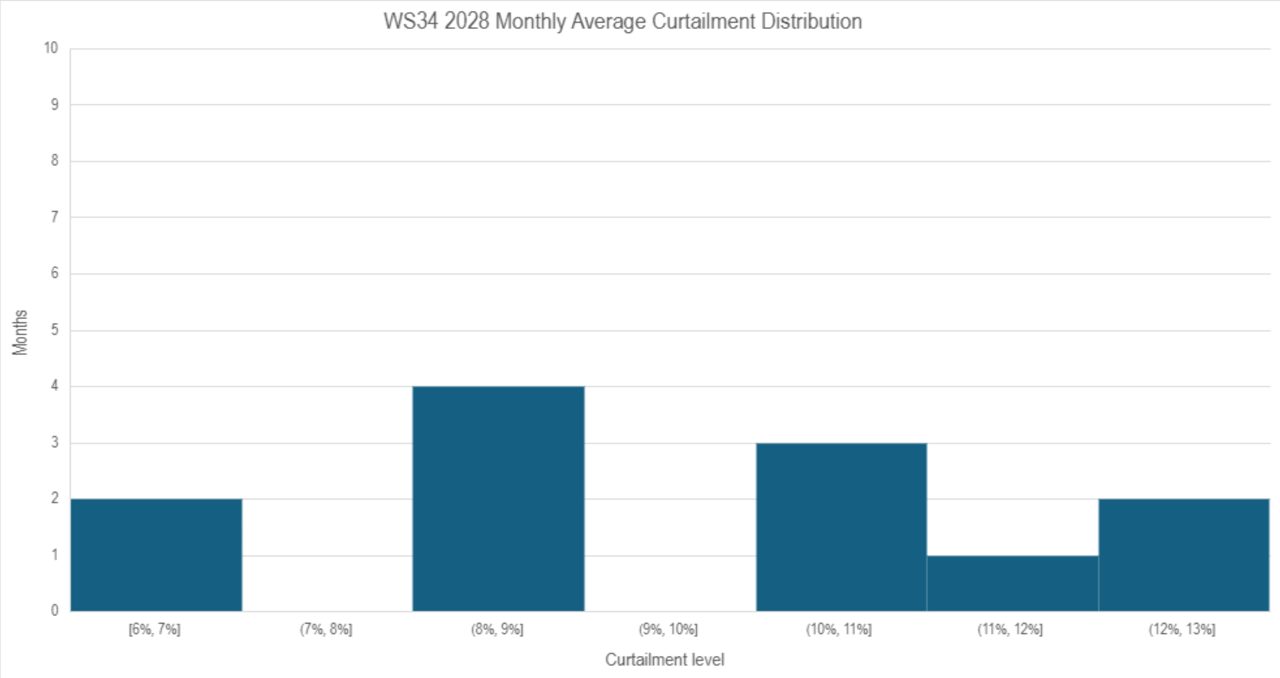
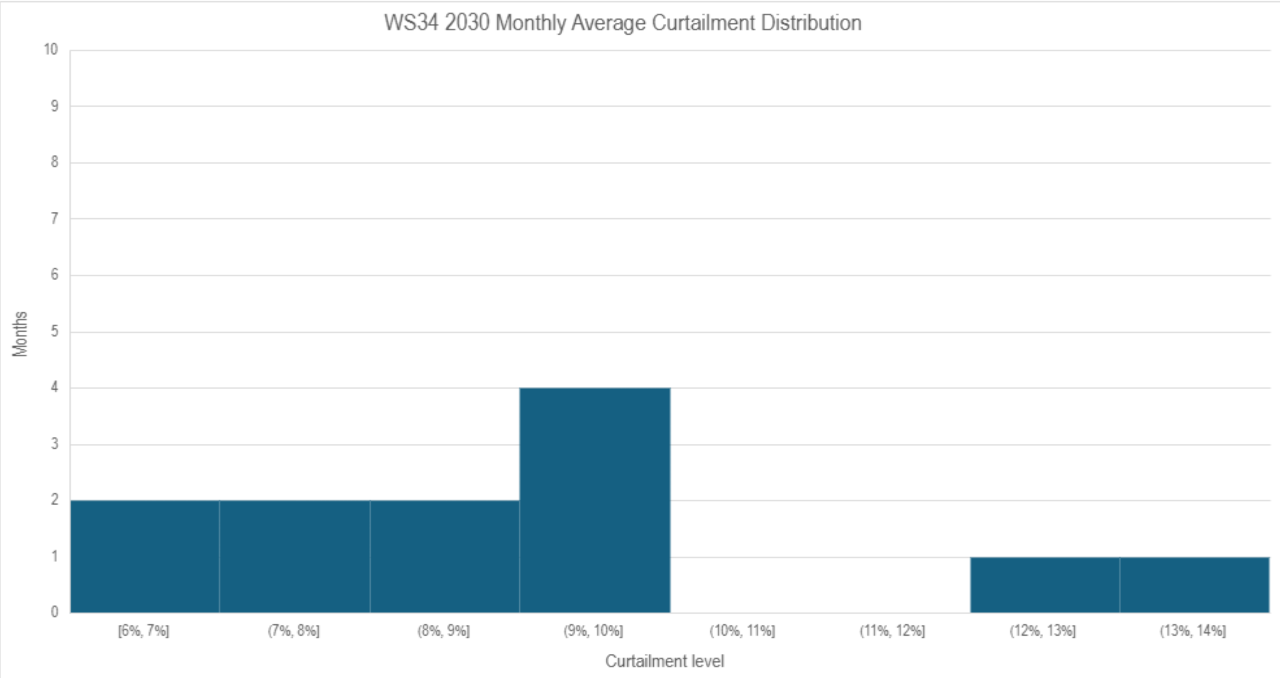


Figure 97: Monthly average curtailment distribution, 2030, WS34 - Article 8(4)(b)



Appendix B.2.3 Article 8(4)(c) Representation as a function of time and day

Figure 98: Average Hourly Curtailment for the Year, 2028, WS4 - Article 8(4)(c)

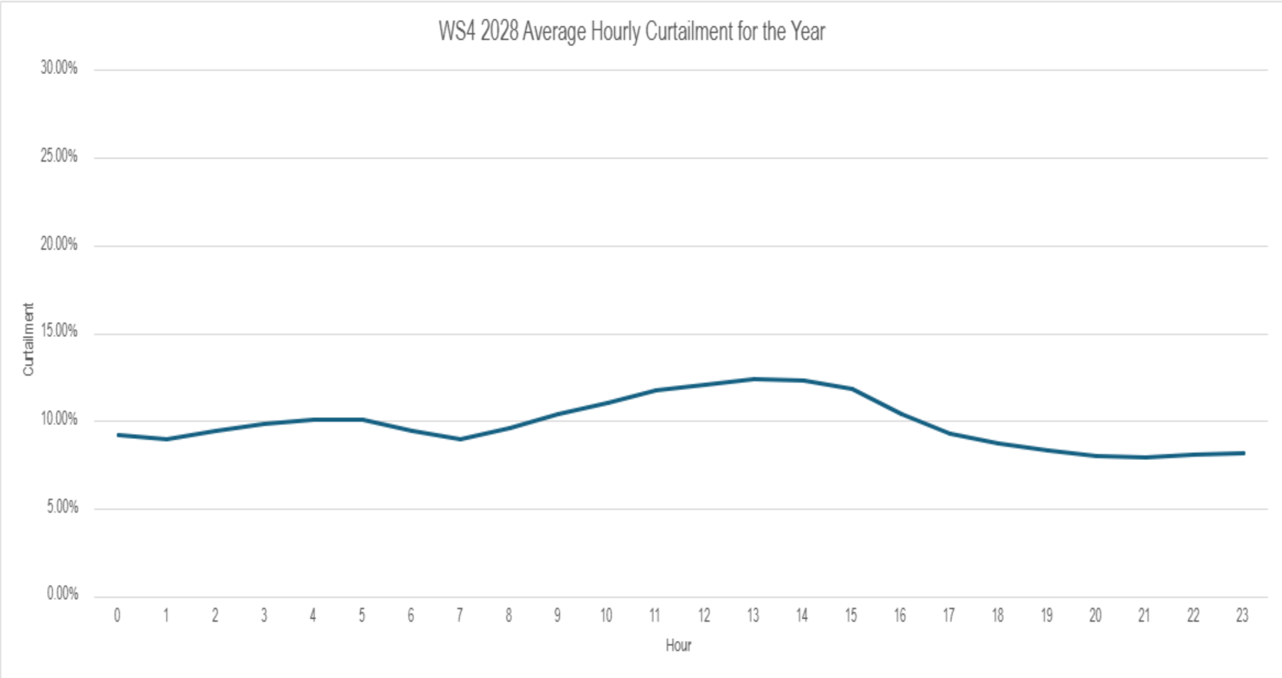


Figure 99: Average Hourly Curtailment for the Year, 2030, WS4 - Article 8(4)(c)

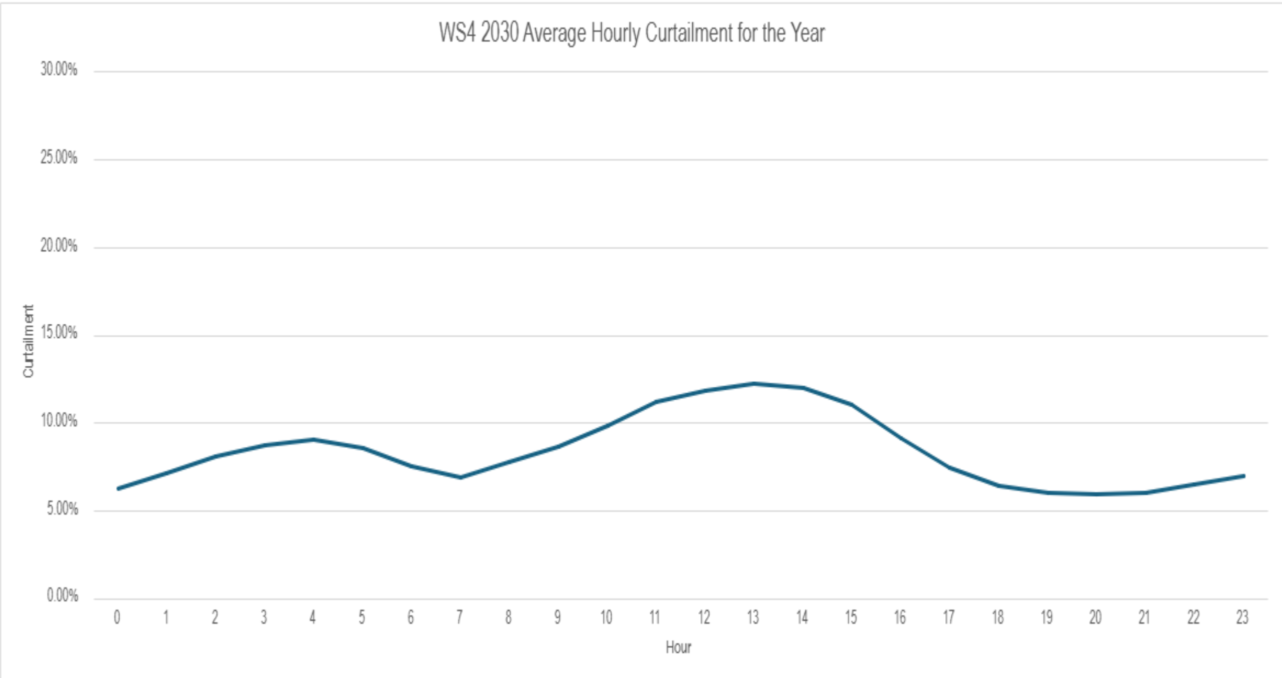


Figure 100: Average Hourly Curtailment for the Year, 2028, WS34 - Article 8(4)(c)

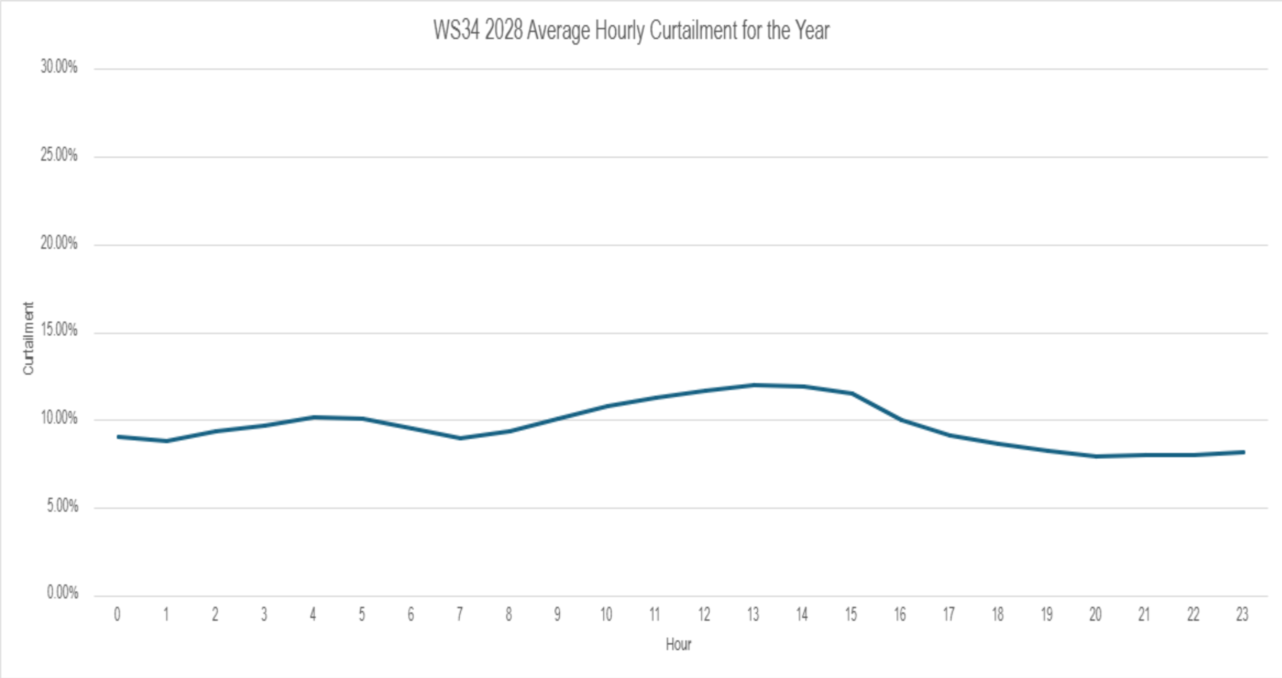


Figure 101: Average Hourly Curtailment for the Year, 2030, WS34 - Article 8(4)(c)

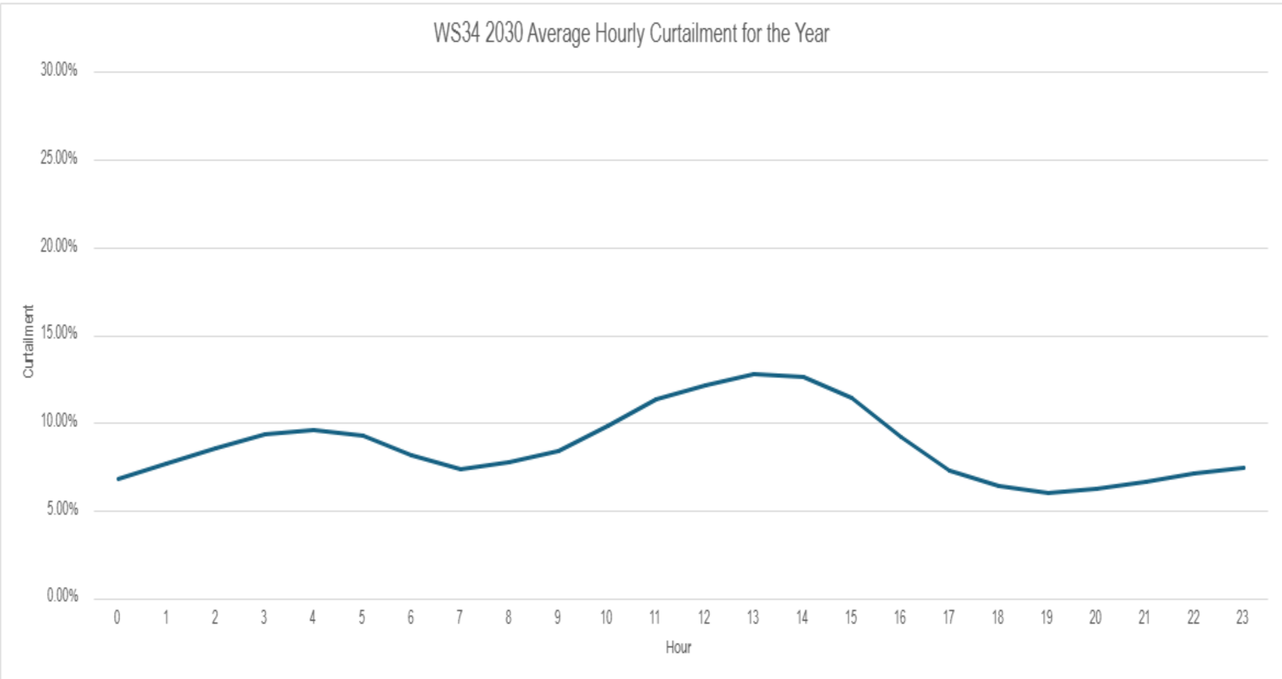


Figure 102: Average Hourly Curtailment per Month, 2028, WS4 - Article 8(4)(c)

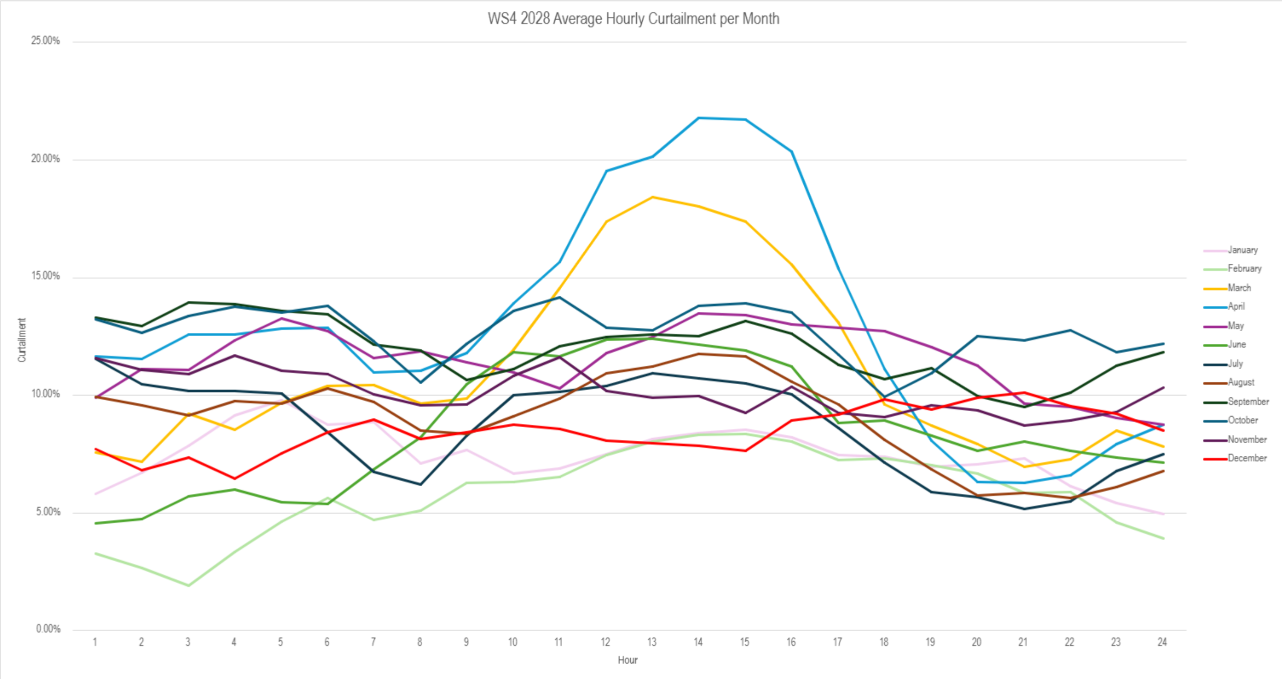


Figure 103: Average Hourly Curtailment per Month, 2030, WS4 - Article 8(4)(c)

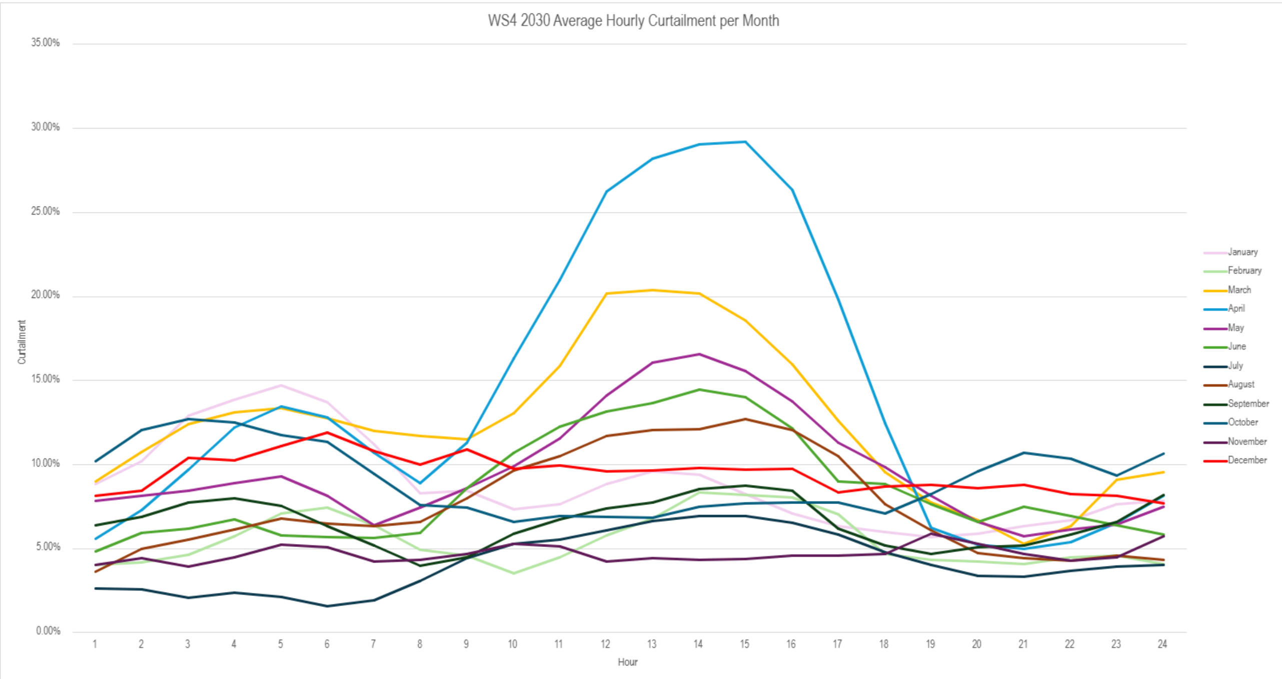


Figure 104: Average Hourly Curtailment per Month, 2028, WS34 - Article 8(4)(c)

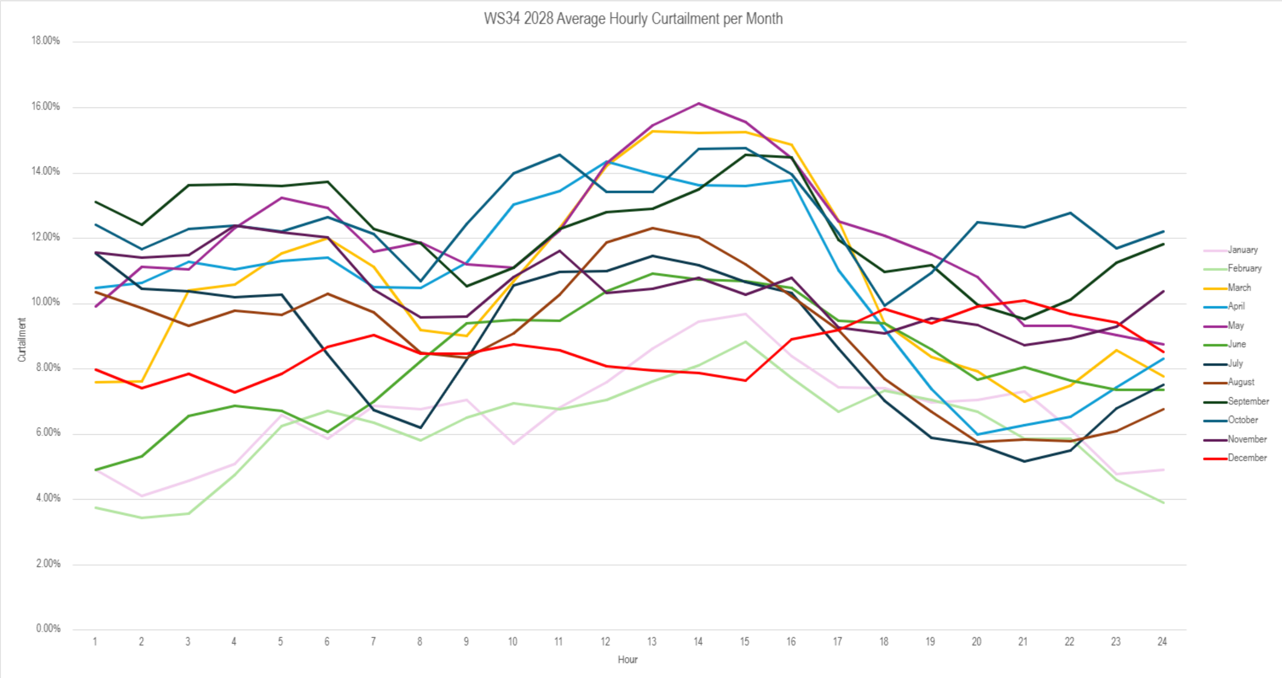
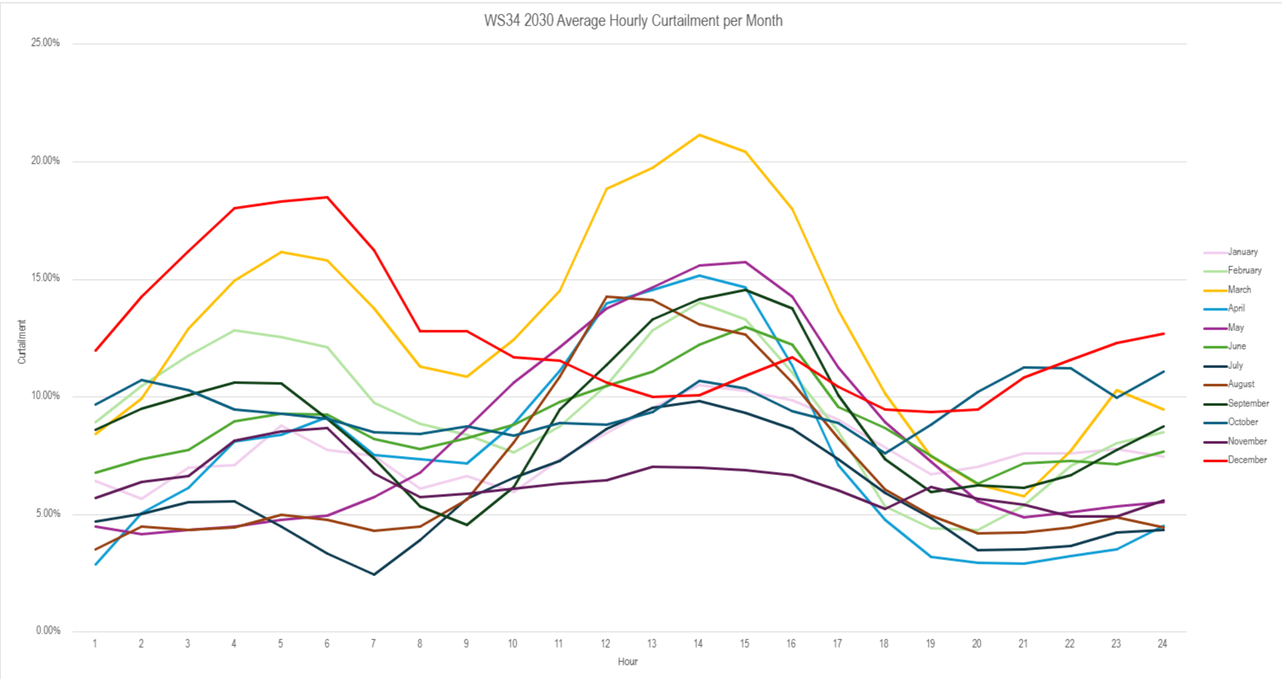


Figure 105: Average Hourly Curtailment per Month, 2030, WS34 - Article 8(4)(c)



Appendix B.2.4 Article 8(4)(d) Correlation

Figure 106: Average weekly curtailed RES vs wind, solar, native load, 2028, WS4 - Article 8(4)(d)

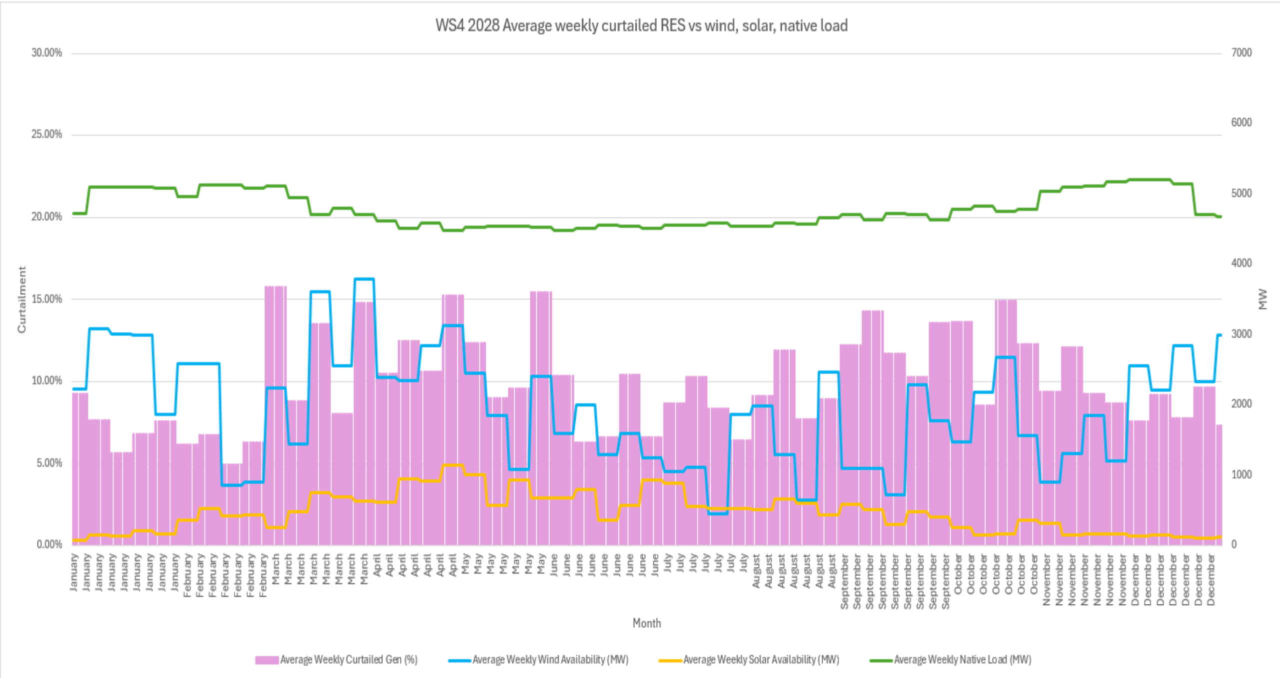


Figure 107: Average monthly curtailed RES vs wind, solar, native load, 2028, WS4 - Article 8(4)(d)

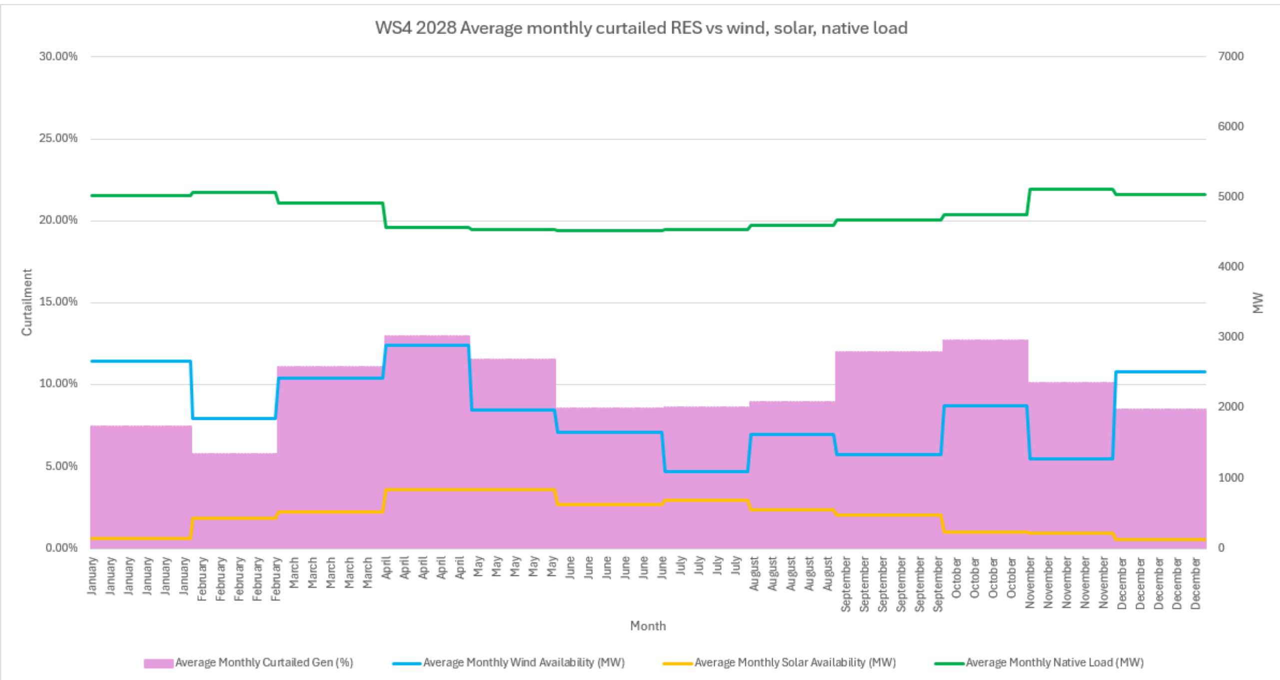


Figure 108: Average weekly curtailed RES vs wind, solar, native load, 2030, WS4 - Article 8(4)(d)

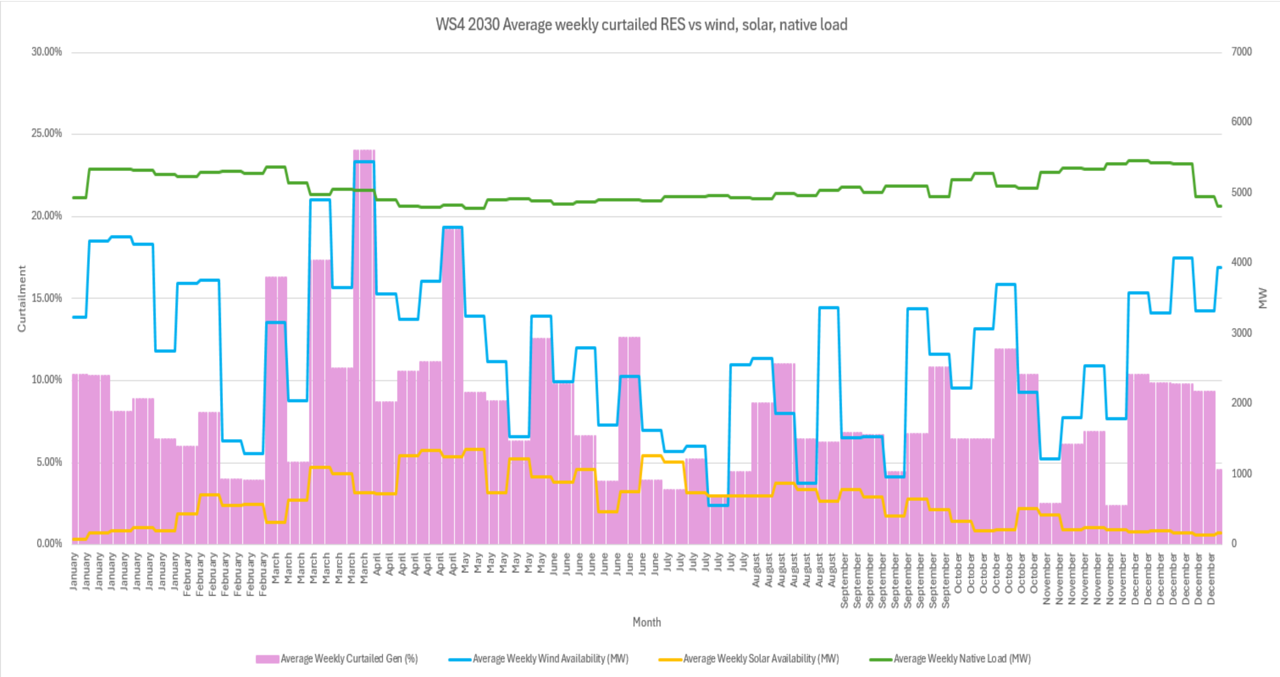


Figure 109: Average monthly curtailed RES vs wind, solar, native load, 2030, WS4 - Article 8(4)(d)

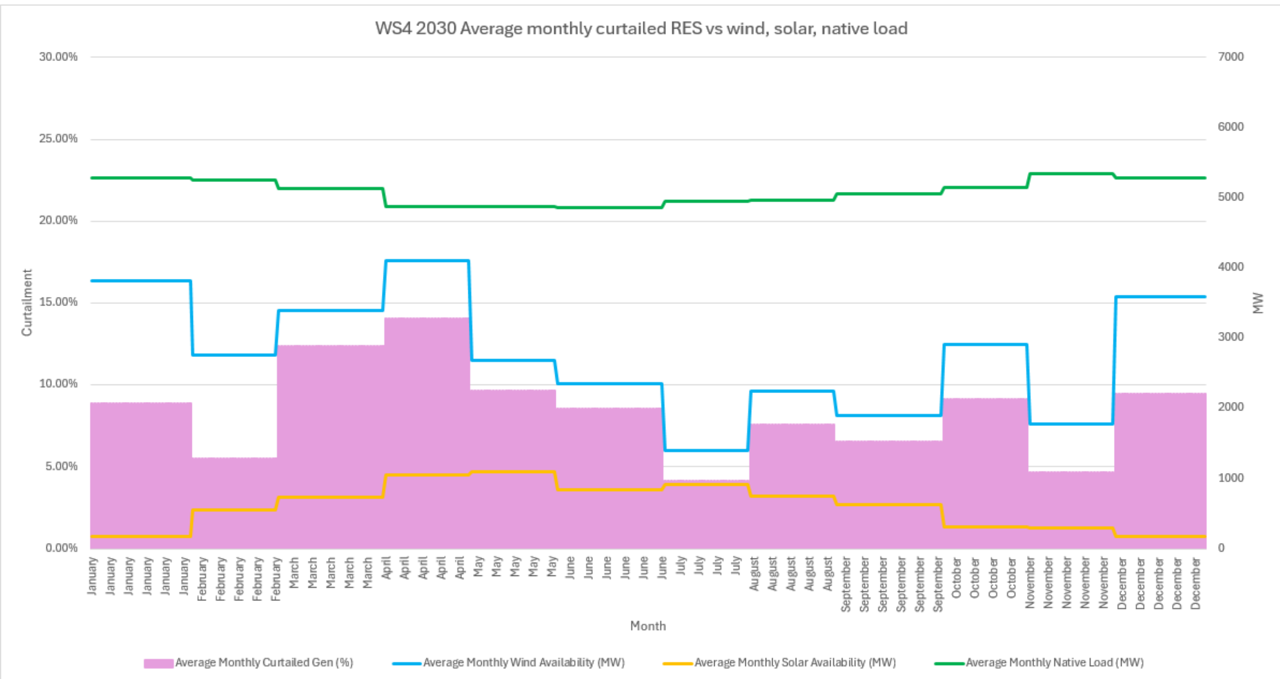


Figure 110: Average weekly curtailed RES vs wind, solar, native load, 2028, WS34 - Article 8(4)(d)

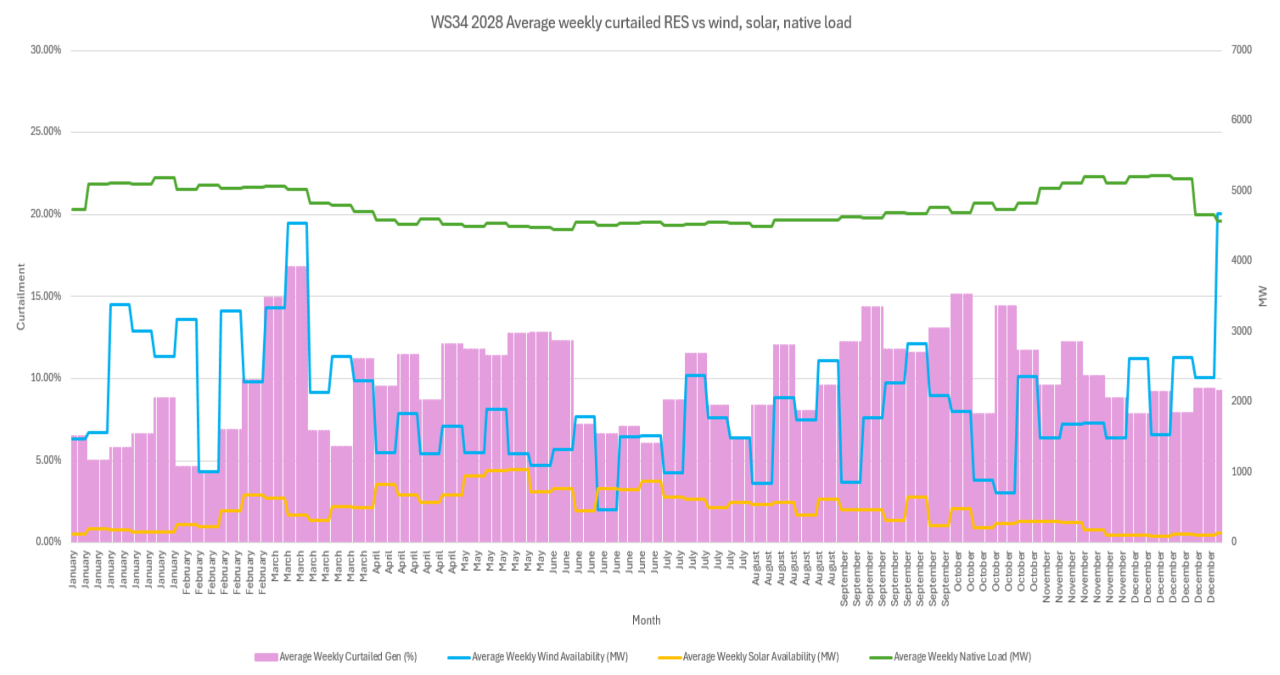


Figure 111: Average monthly curtailed RES vs wind, solar, native load, 2028, WS34 - Article 8(4)(d)

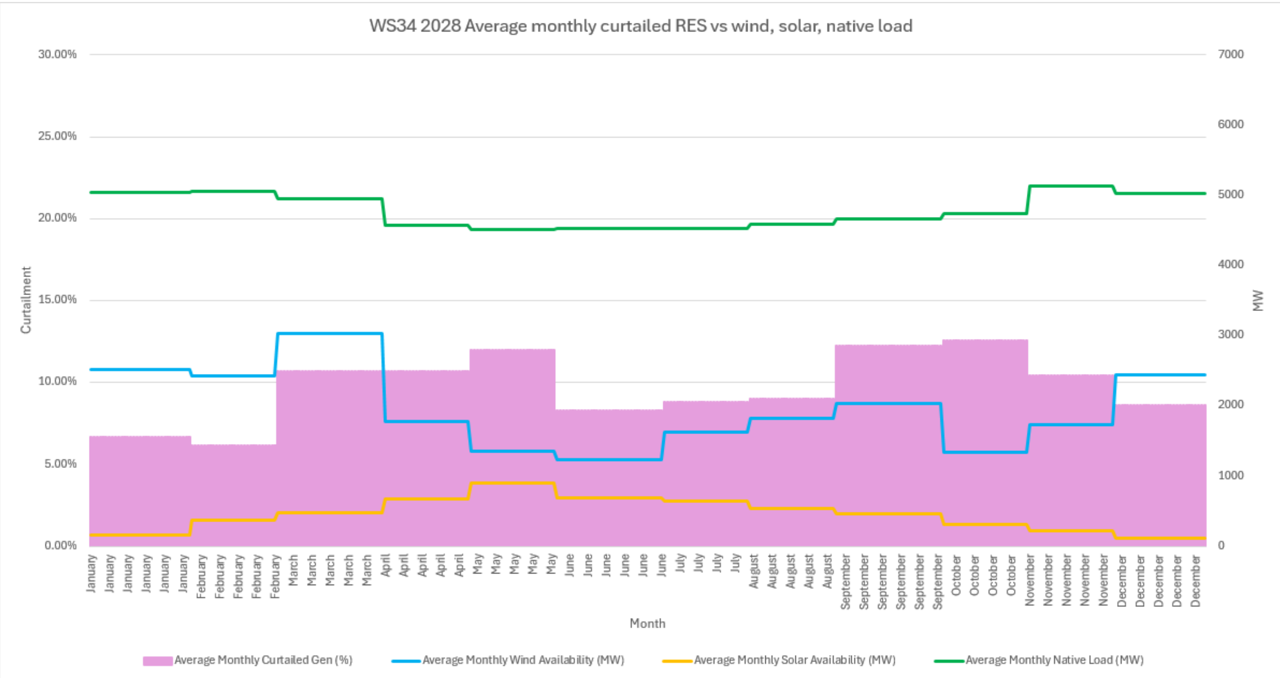


Figure 112: Average weekly curtailed RES vs wind, solar, native load, 2030, WS34 - Article 8(4)(d)

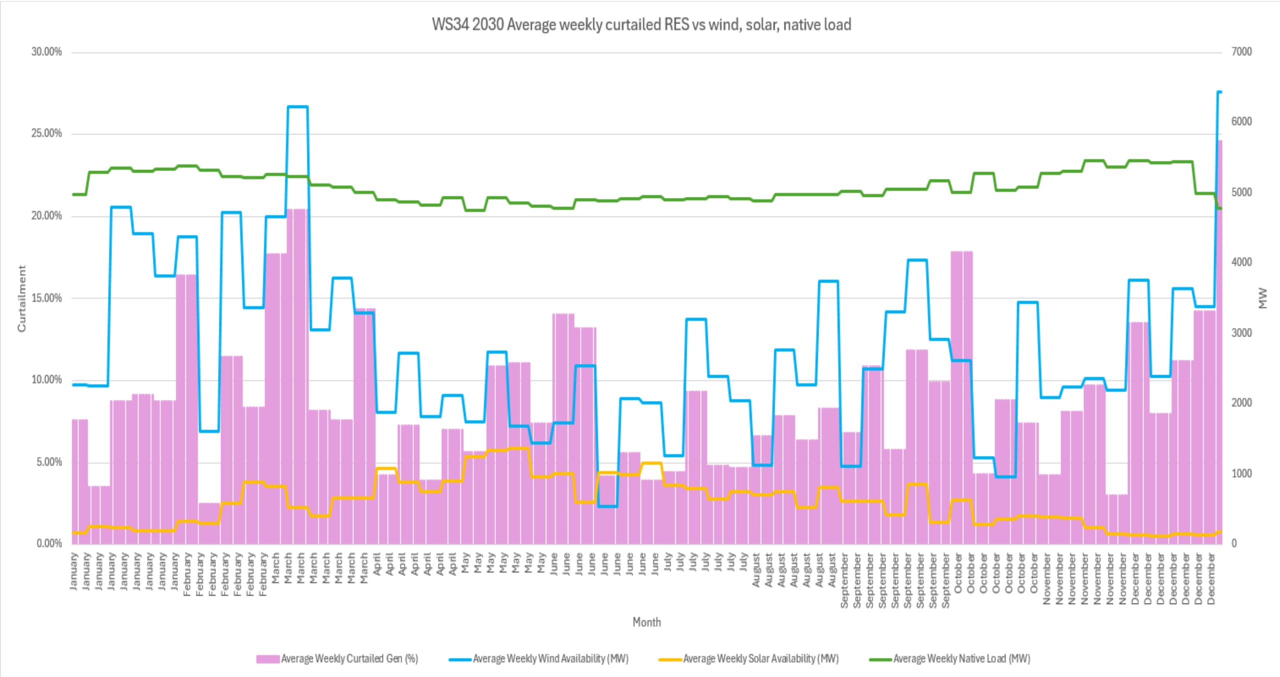


Figure 113: Average monthly curtailed RES vs wind, solar, native load, 2030, WS34 - Article 8(4)(d)

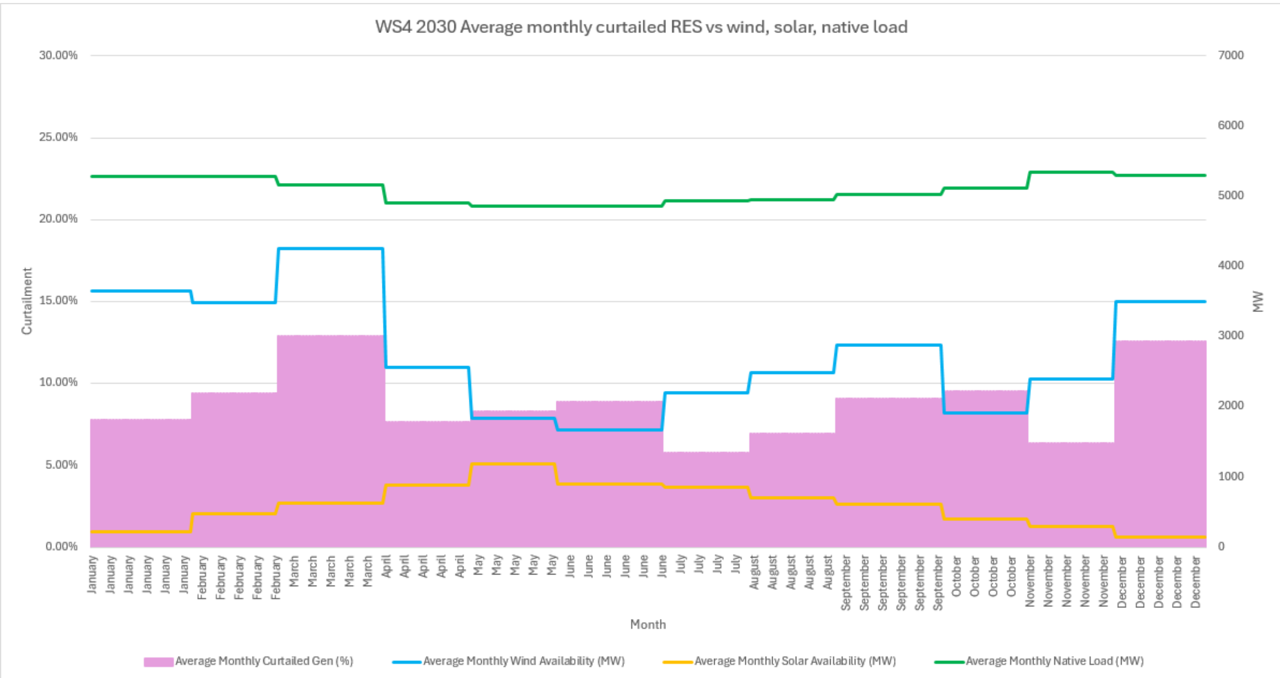


Figure 114: Correlation Distribution Wind vs Curtailed Generation, 2028, WS4 - Article 8(4)(d)

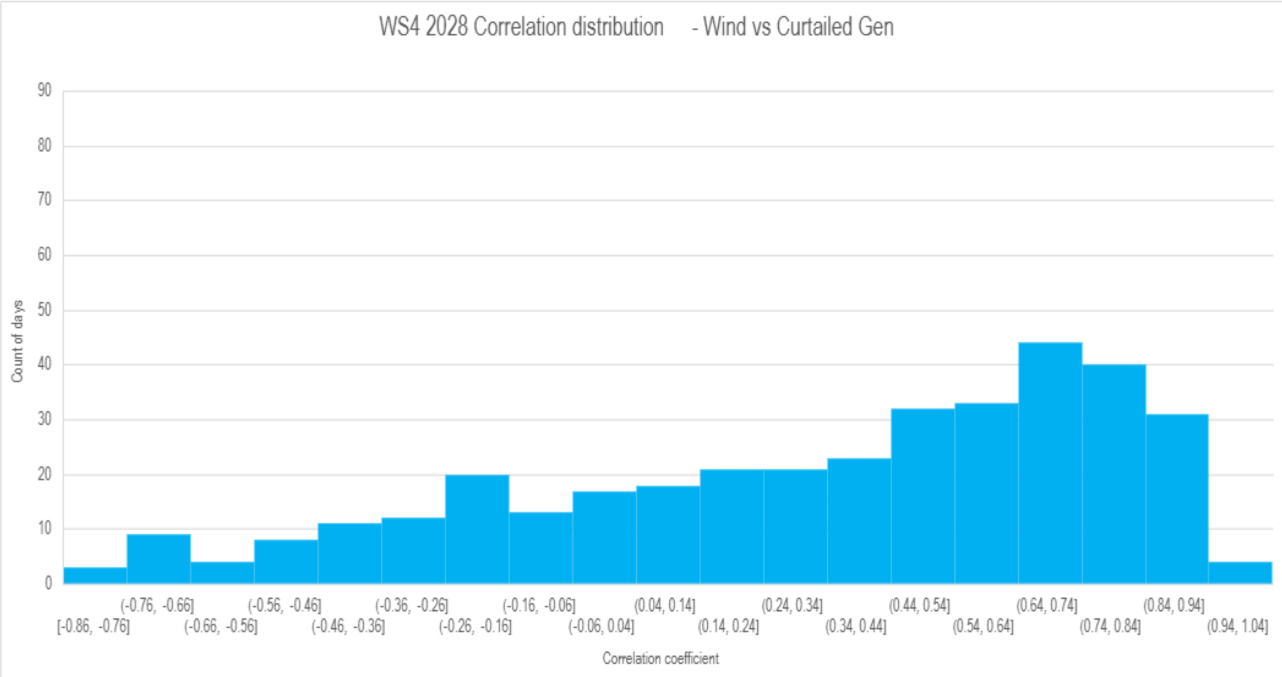


Figure 115: Correlation Distribution Solar vs Curtailed Generation, 2028, WS4 - Article 8(4)(d)

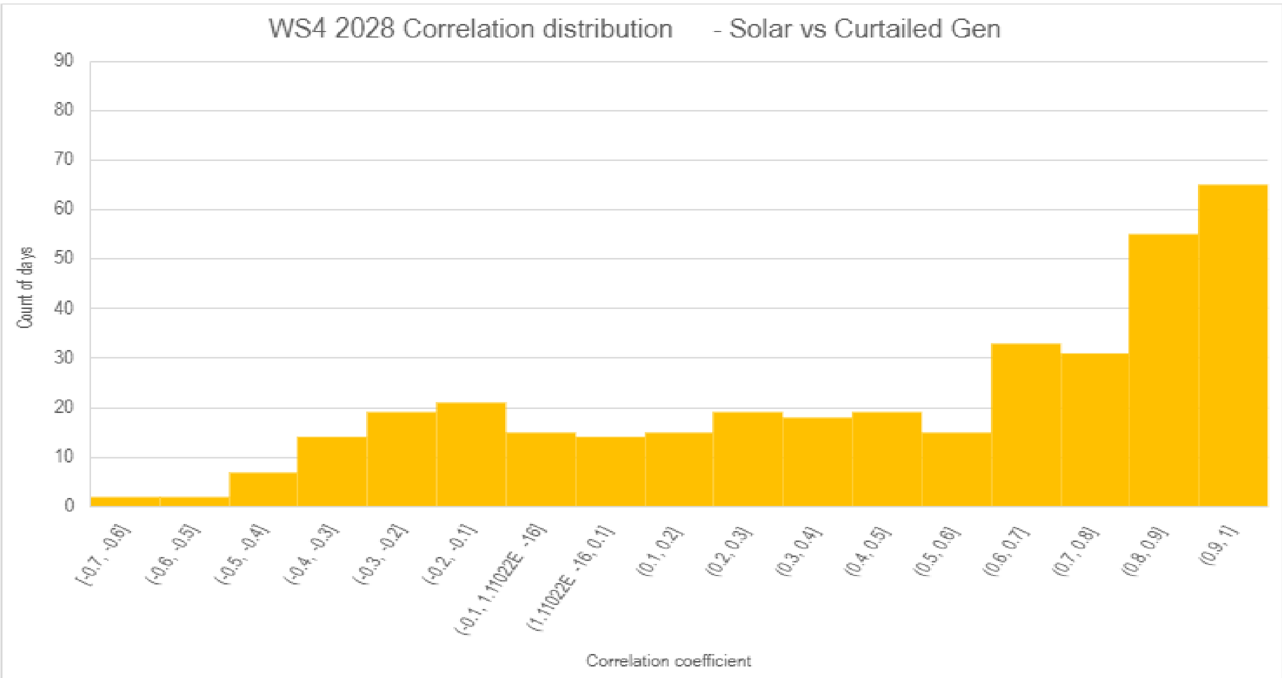


Figure 116: Correlation Distribution Native Load vs Curtailed Generation (as per the ACER Methodology requirement), 2028, WS4 - Article 8(4)(d)

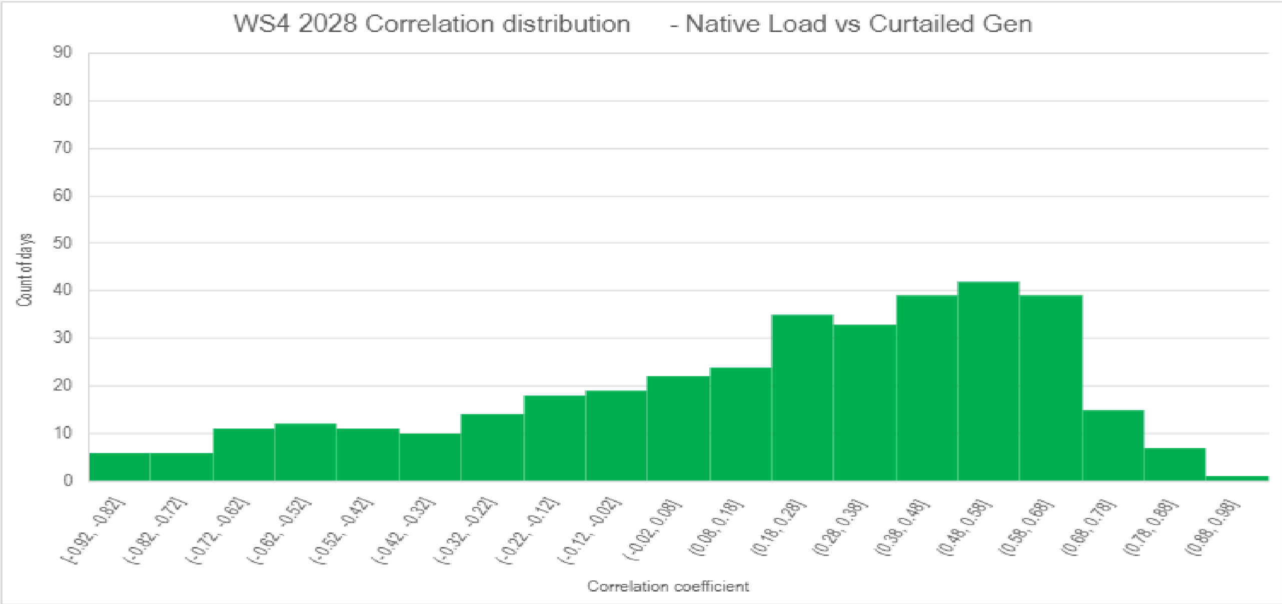


Figure 117: Corelation distribution for wind vs curtailed generation (positive curtailment), 2028, WS4 - Article 8(4)(d)

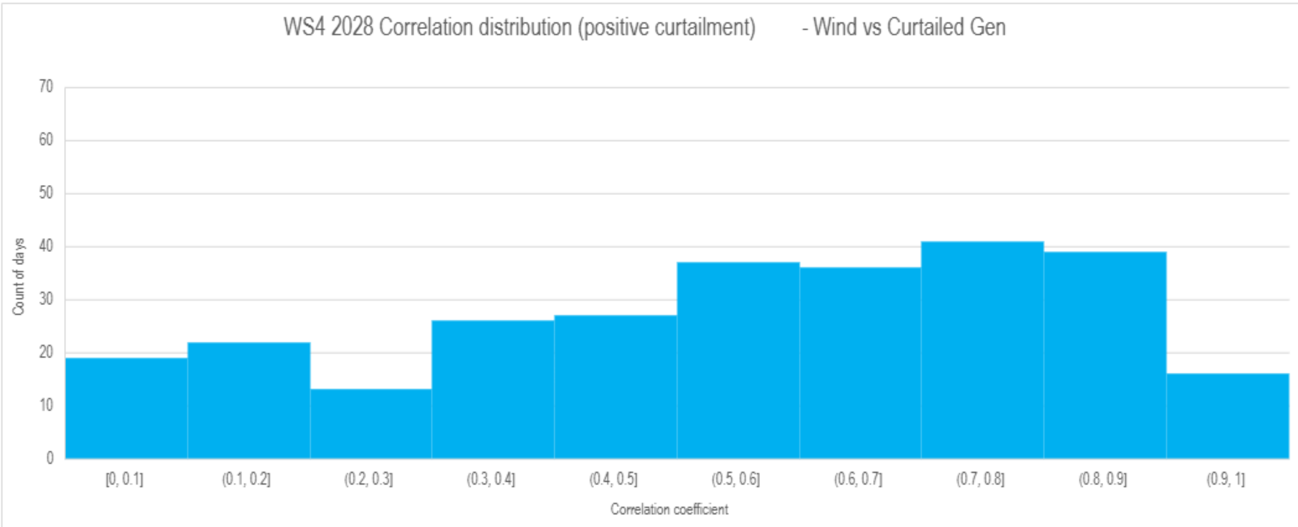


Figure 118: Corelation distribution for Solar vs curtailed generation (positive curtailment), 2028, WS4 - Article 8(4)(d)

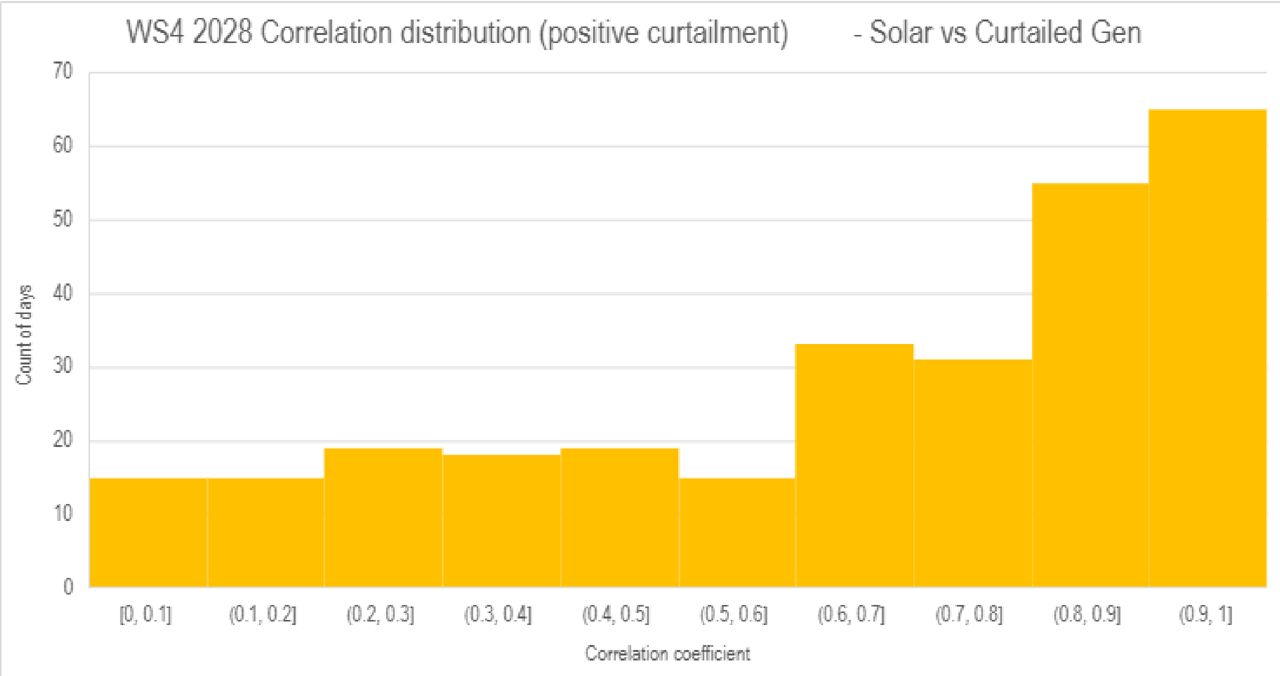


Figure 119: Correlation distribution for Native load vs curtailed generation (positive curtailment), 2028, WS4 - Article 8(4)(d)

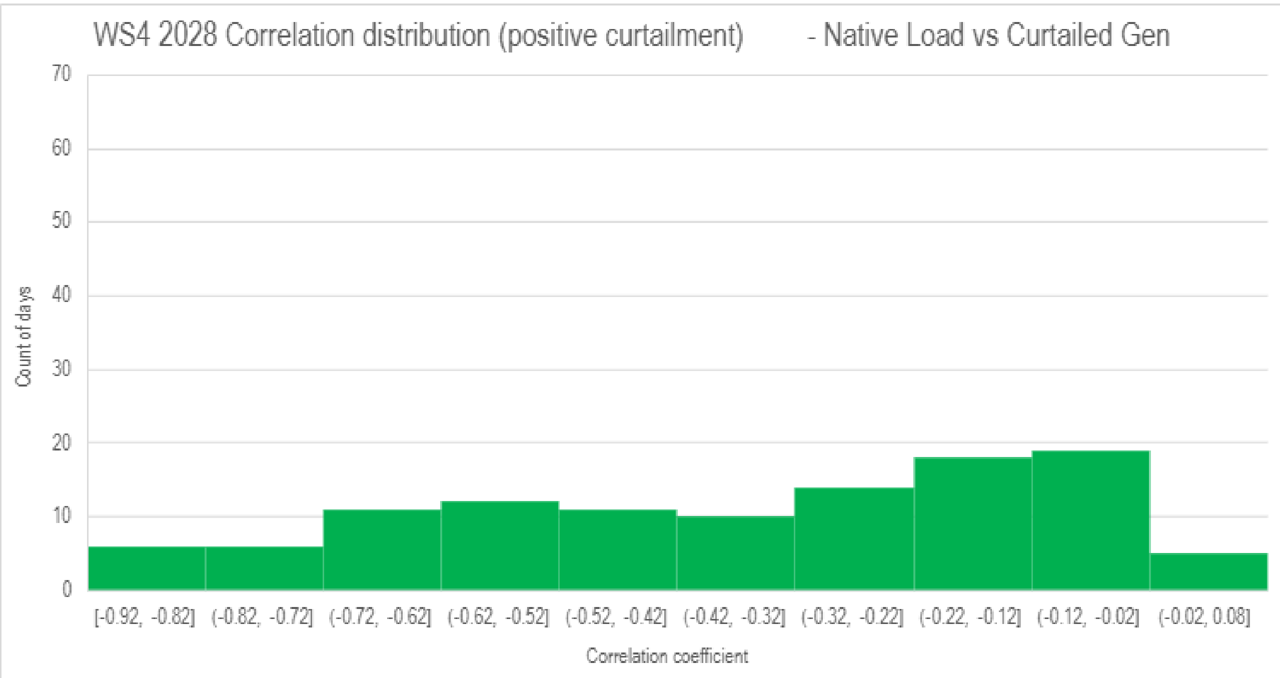


Figure 120: Correlation Distribution Wind vs Curtailed Generation, 2030, WS4 - Article 8(4)(d)

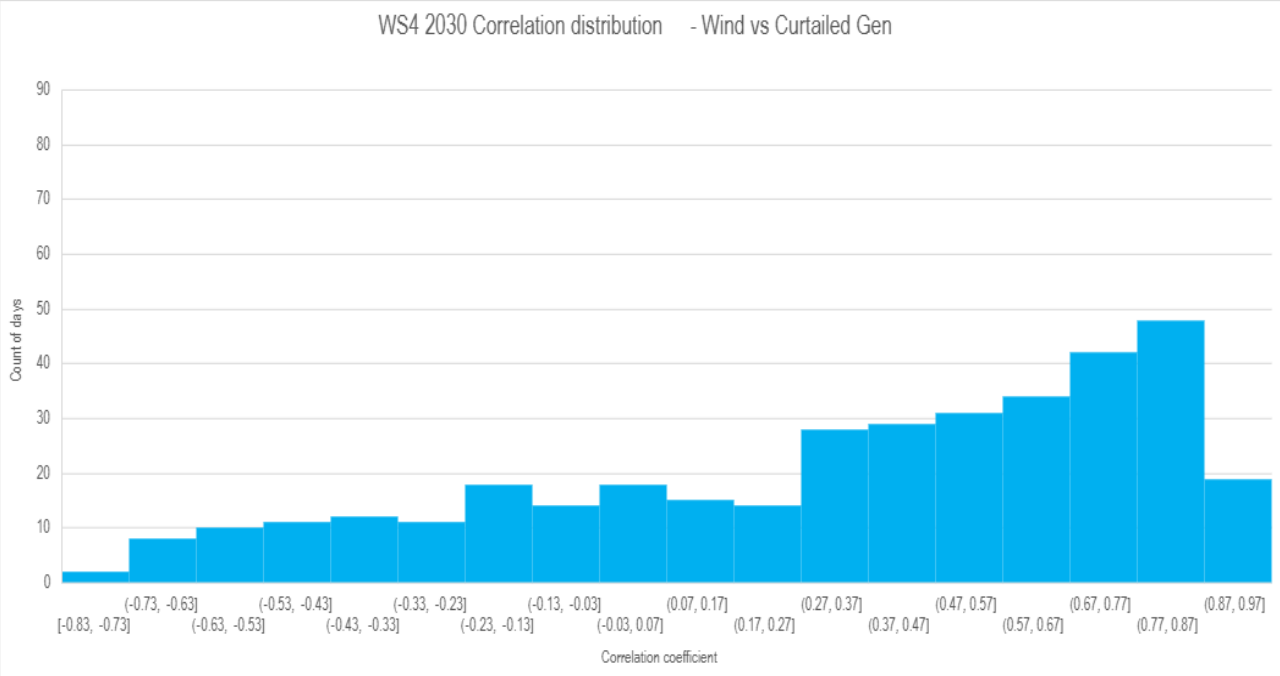


Figure 121: Correlation Distribution Solar vs Curtailed Generation, 2030, WS4 - Article 8(4)(d)

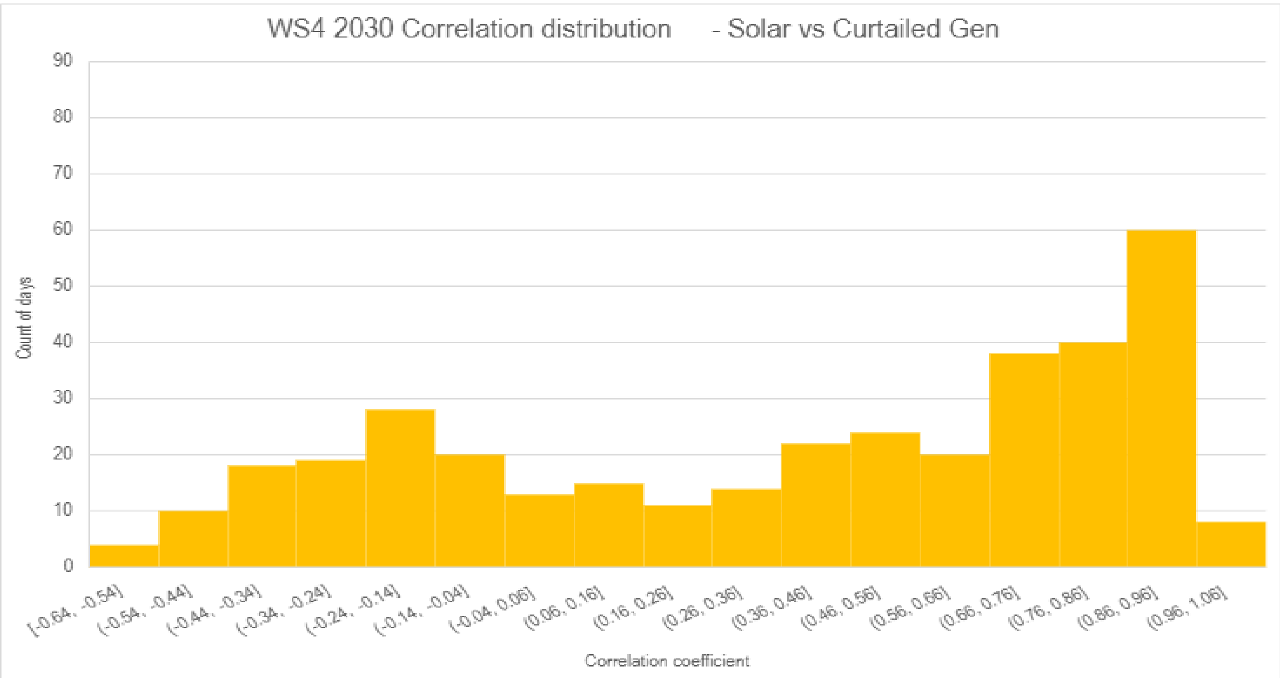


Figure 122: Correlation Distribution Native Load vs Curtailed Generation (as per the ACER Methodology requirement), 2030, WS4 - Article 8(4)(d)

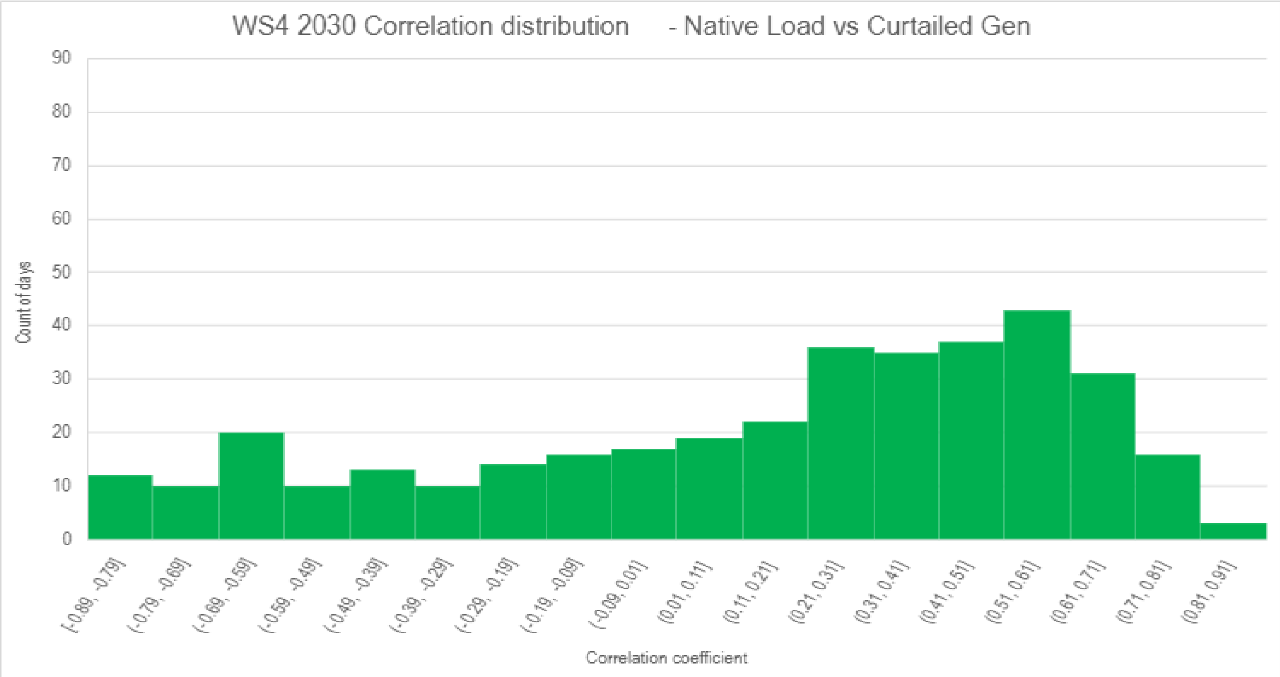


Figure 123: Correlation Distribution Wind vs Curtailed Generation (Positive curtailment), 2030, WS4 - Article 8(4)(d)

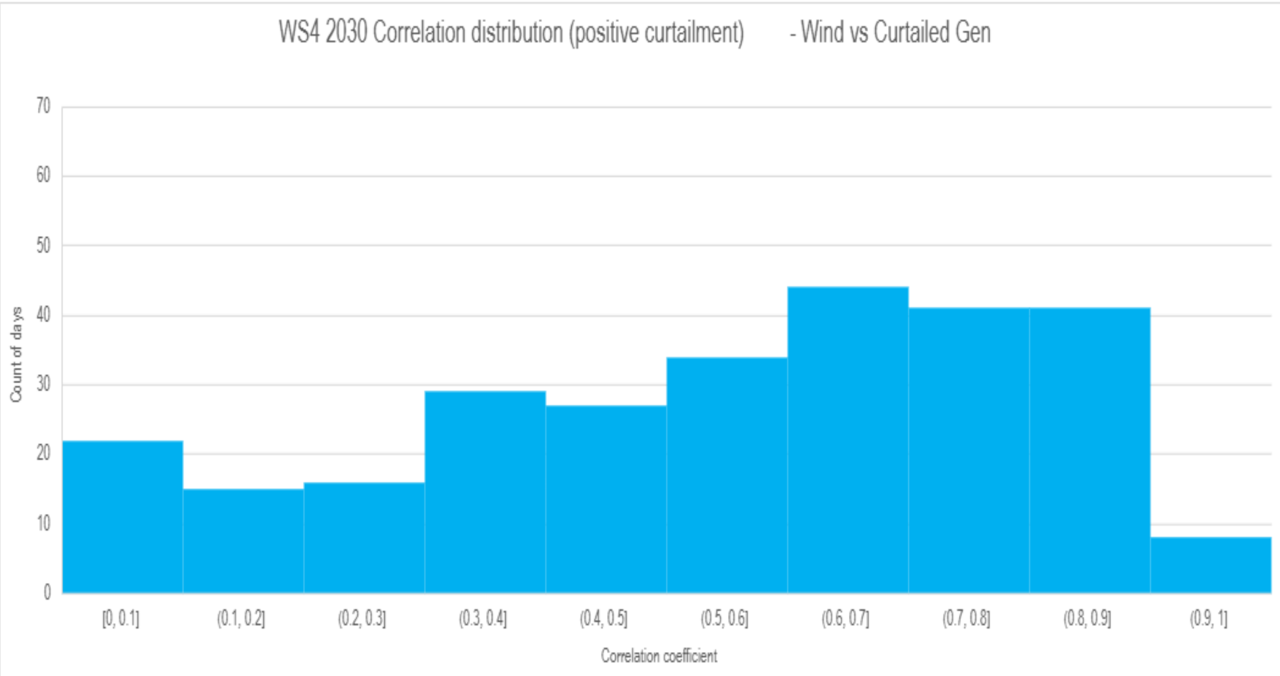


Figure 124: Correlation Distribution Solar vs Curtailed Generation (Positive curtailment), 2030, WS4 - Article 8(4)(d)

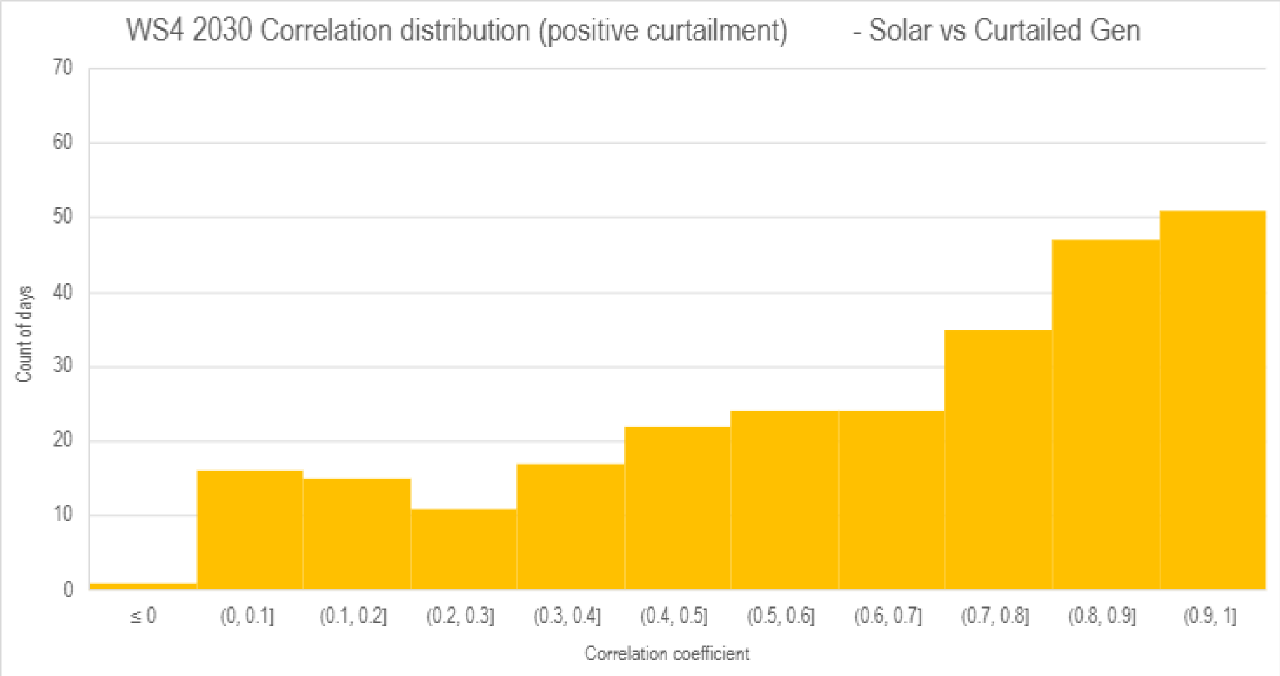


Figure 125: Correlation Distribution Native Load vs Curtailed Generation (as per the ACER Methodology requirement) (Positive curtailment), 2030, WS4 - Article 8(4)(d)

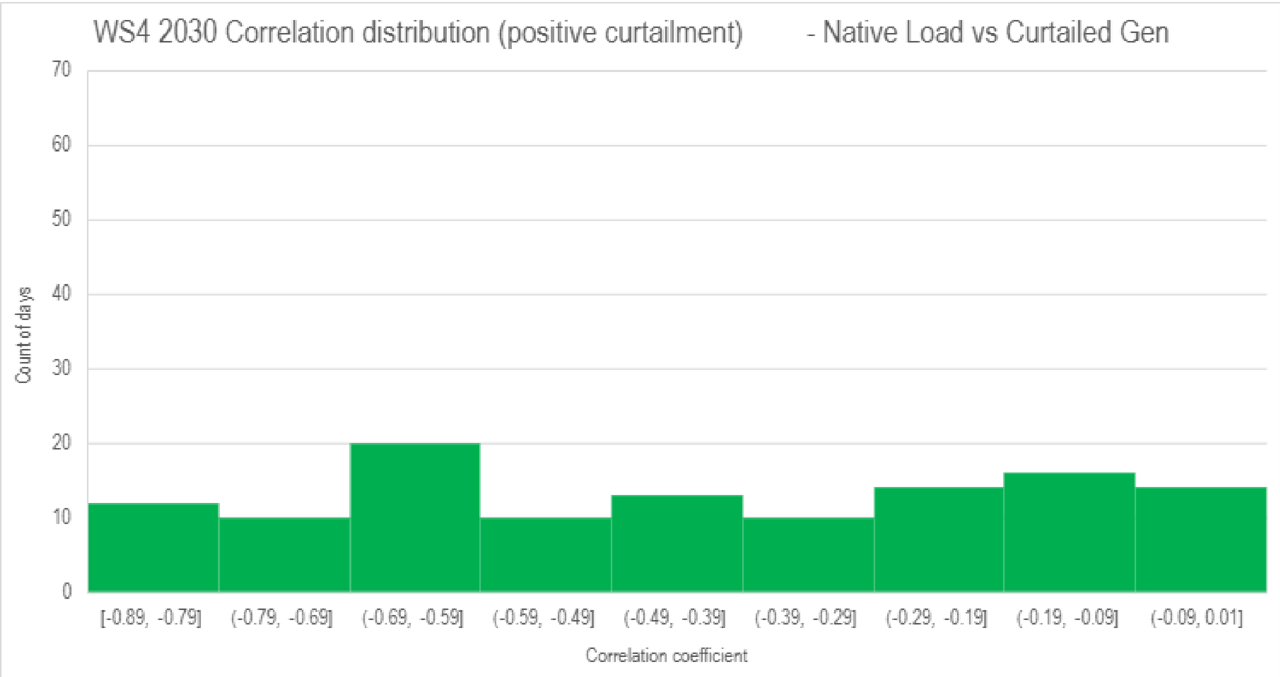


Figure 126: Correlation Distribution Wind vs Curtailed Generation, 2028, WS34 - Article 8(4)(d)

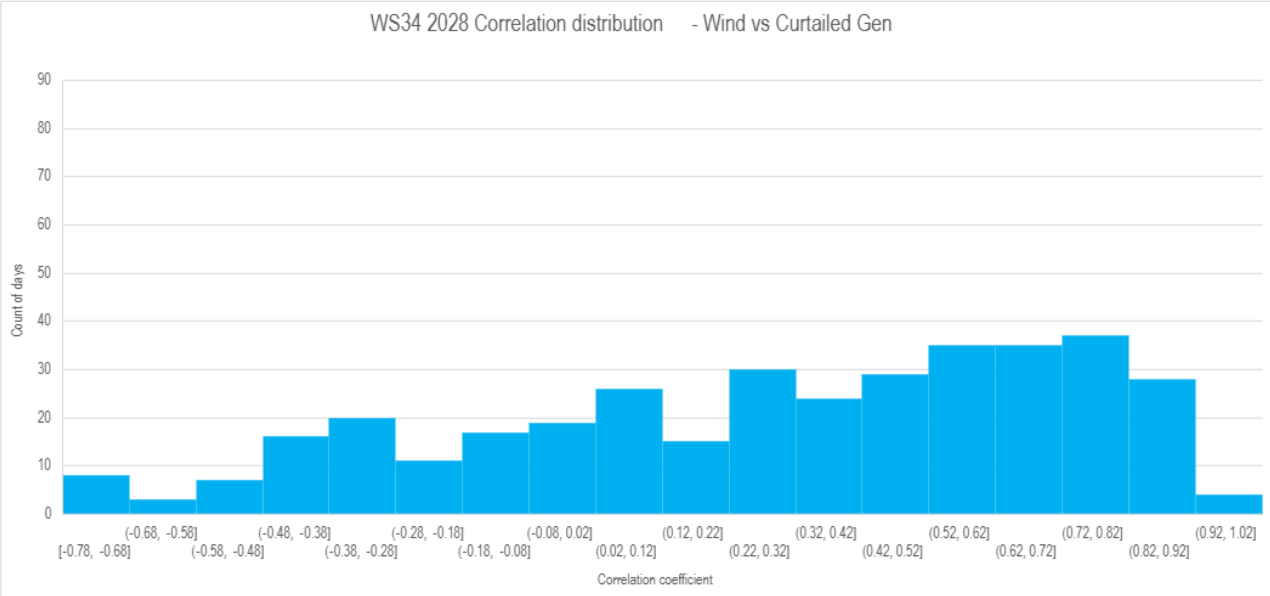


Figure 127: Correlation Distribution Solar vs Curtailed Generation, 2028, WS34 - Article 8(4)(d)

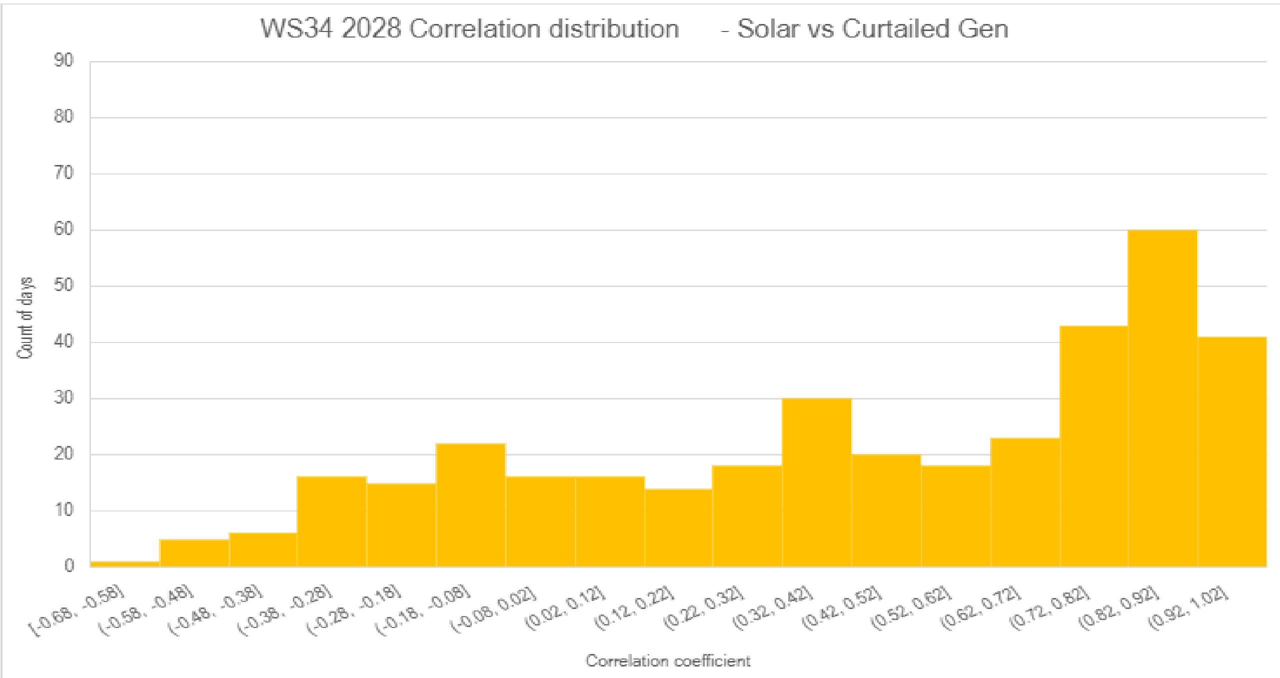


Figure 128: Correlation Distribution Native Load vs Curtailed Generation (as per the ACER Methodology requirement), 2028, WS34 - Article 8(4)(d)

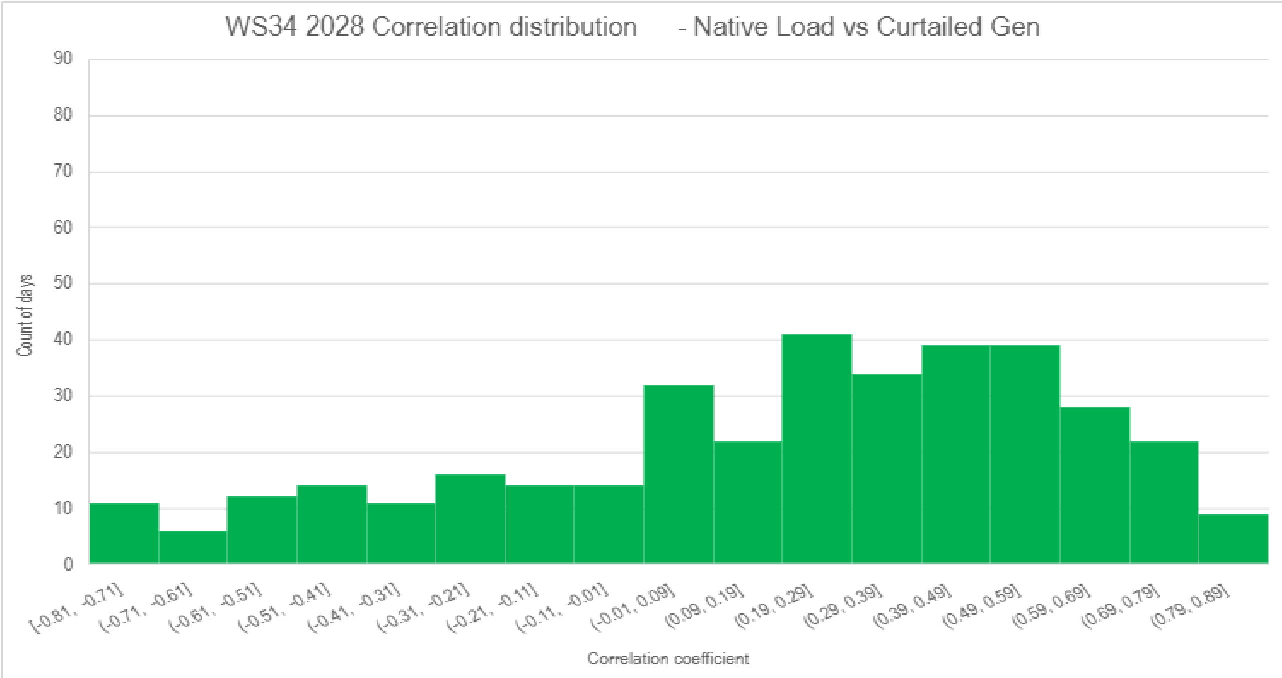


Figure 129: Correlation Distribution Wind vs Curtailed Generation (Positive curtailment), 2028, WS34 - Article 8(4)(d)

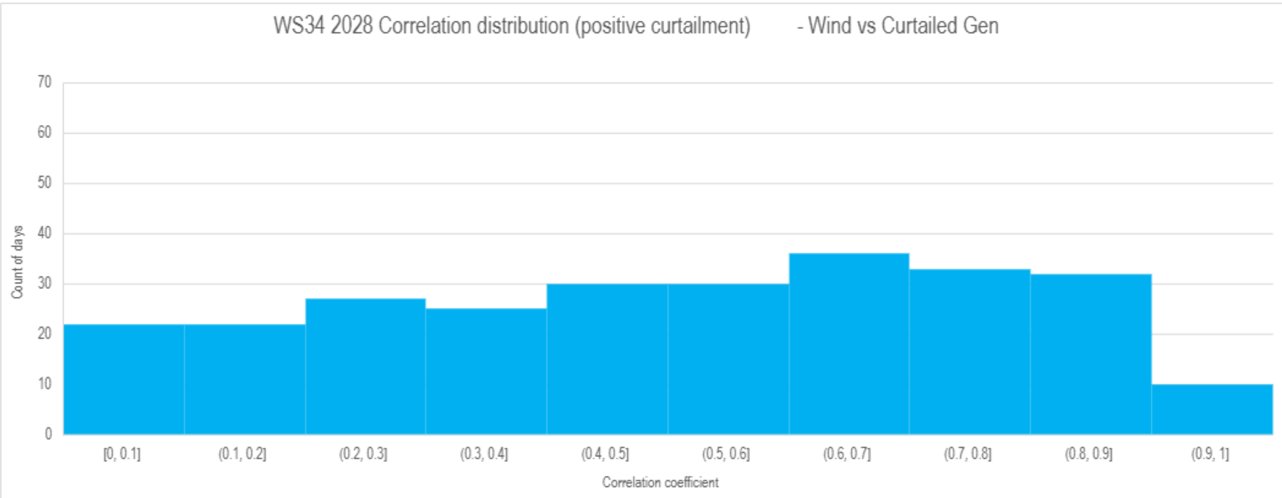


Figure 130: Correlation Distribution Solar vs Curtailed Generation (Positive curtailment), 2028, WS34 - Article 8(4)(d)

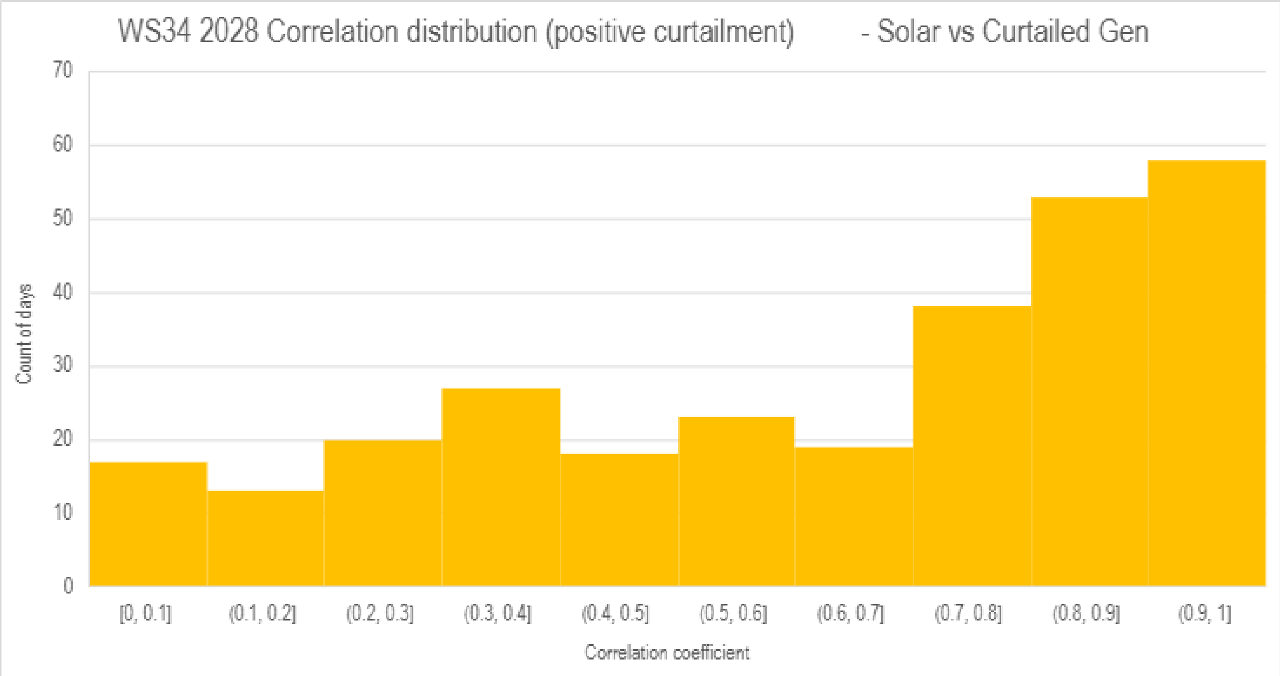


Figure 131: Correlation Distribution Native Load vs Curtailed Generation (as per the ACER Methodology requirement) (Positive curtailment), 2028, WS34 - Article 8(4)(d)

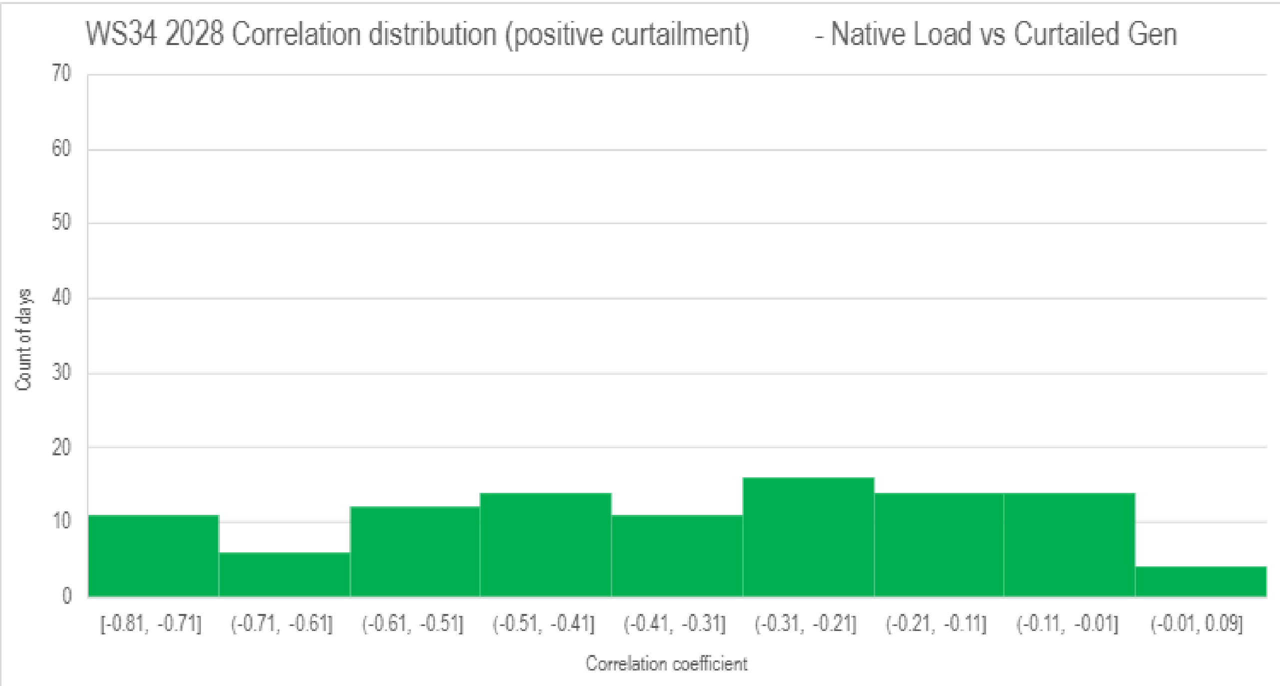


Figure 132: Correlation Distribution Wind vs Curtailed Generation, 2030, WS34 - Article 8(4)(d)

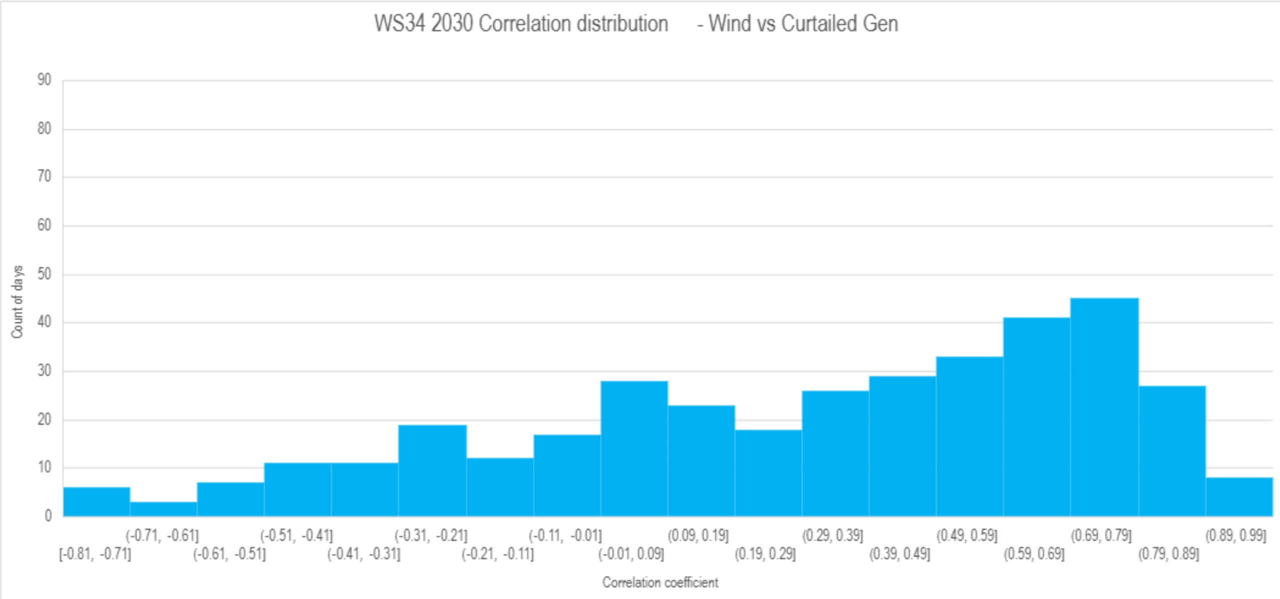


Figure 133: Correlation Distribution Solar vs Curtailed, 2030, WS34 - Article 8(4)(d)

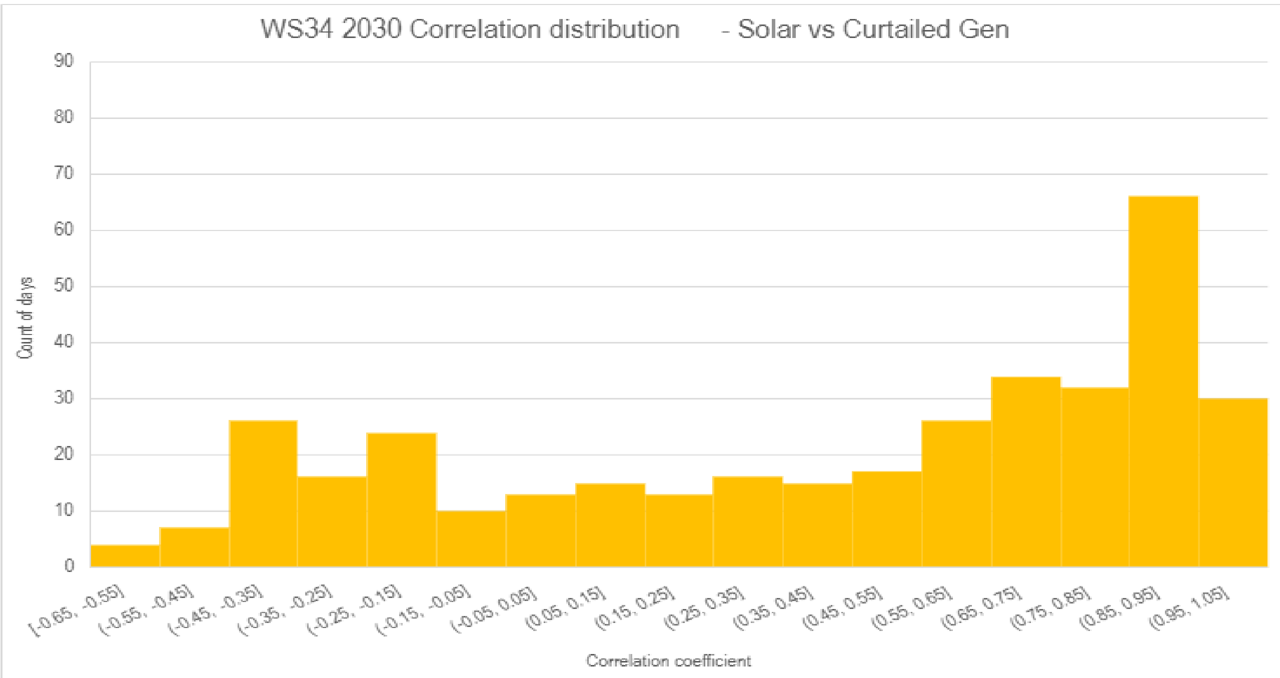


Figure 134: Correlation Distribution Native Load vs Curtailed Generation (as per the ACER Methodology requirement), 2030, WS34 - Article 8(4)(d)

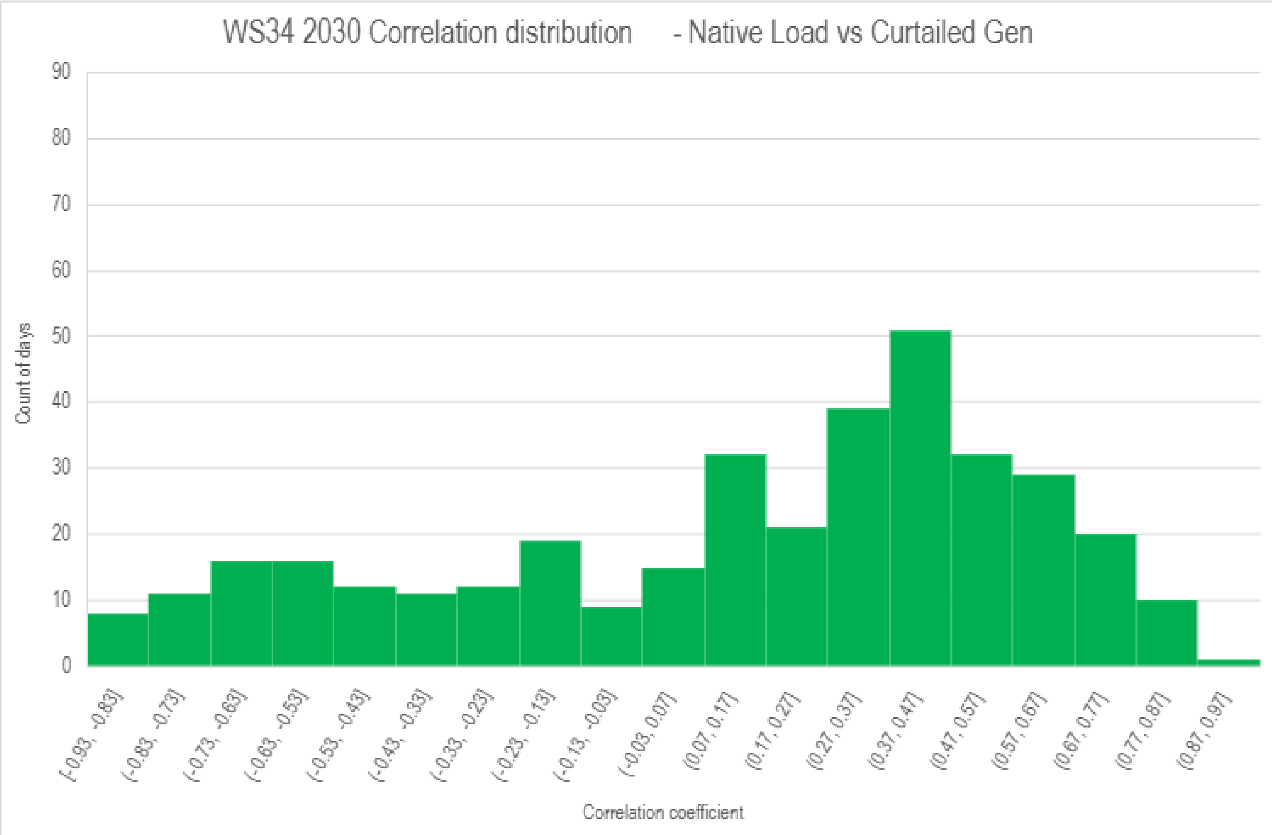


Figure 135: Correlation Distribution Wind vs Curtailed Generation (Positive curtailment), 2030, WS34 - Article 8(4)(d)

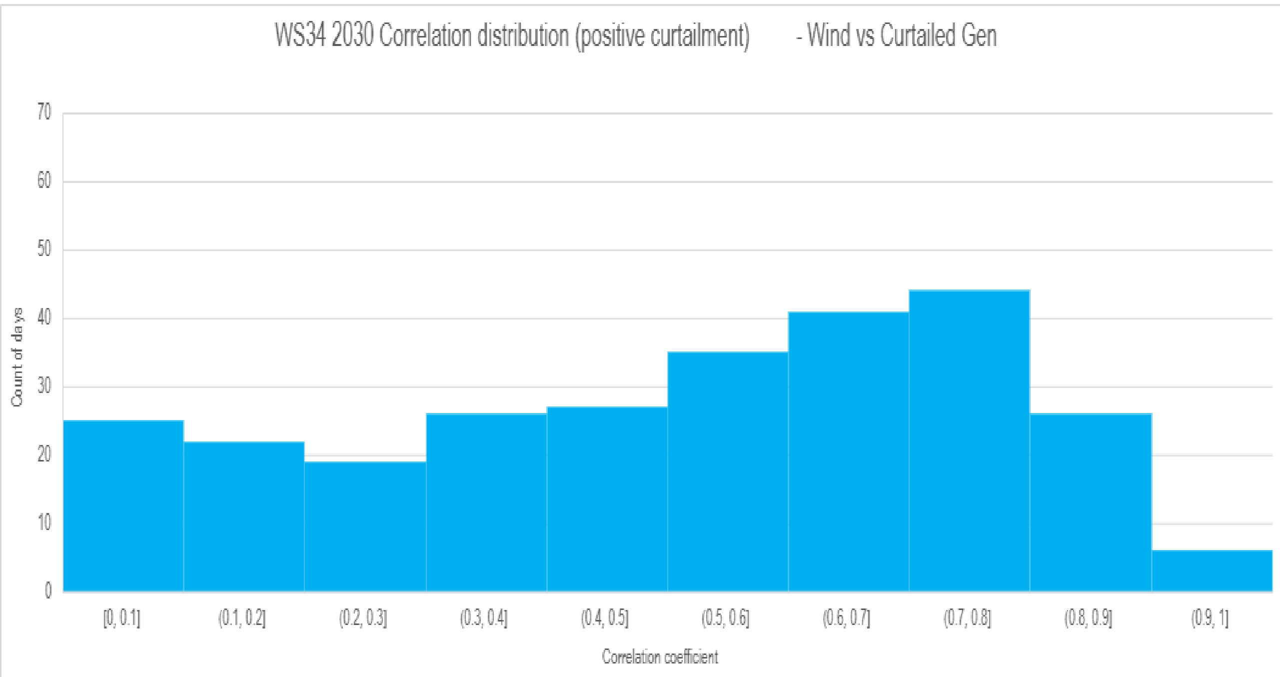


Figure 136: Correlation Distribution Solar vs Curtailed Generation (Positive curtailment), 2030, WS34 - Article 8(4)(d)

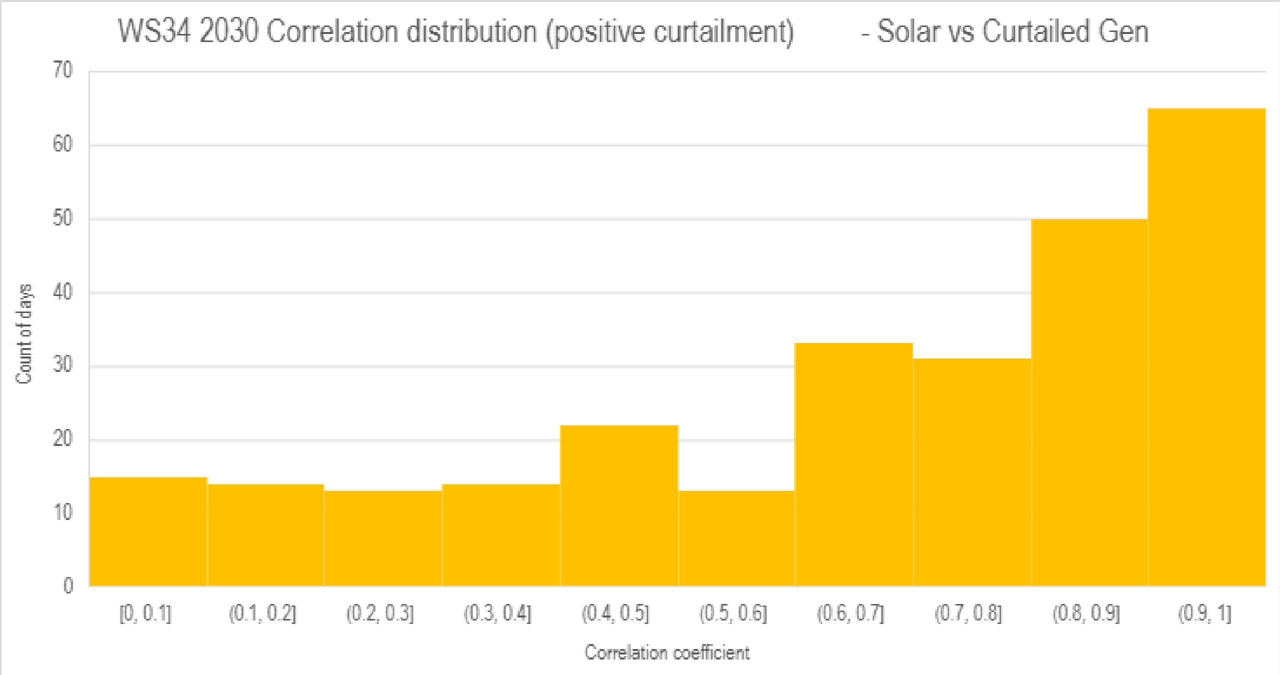
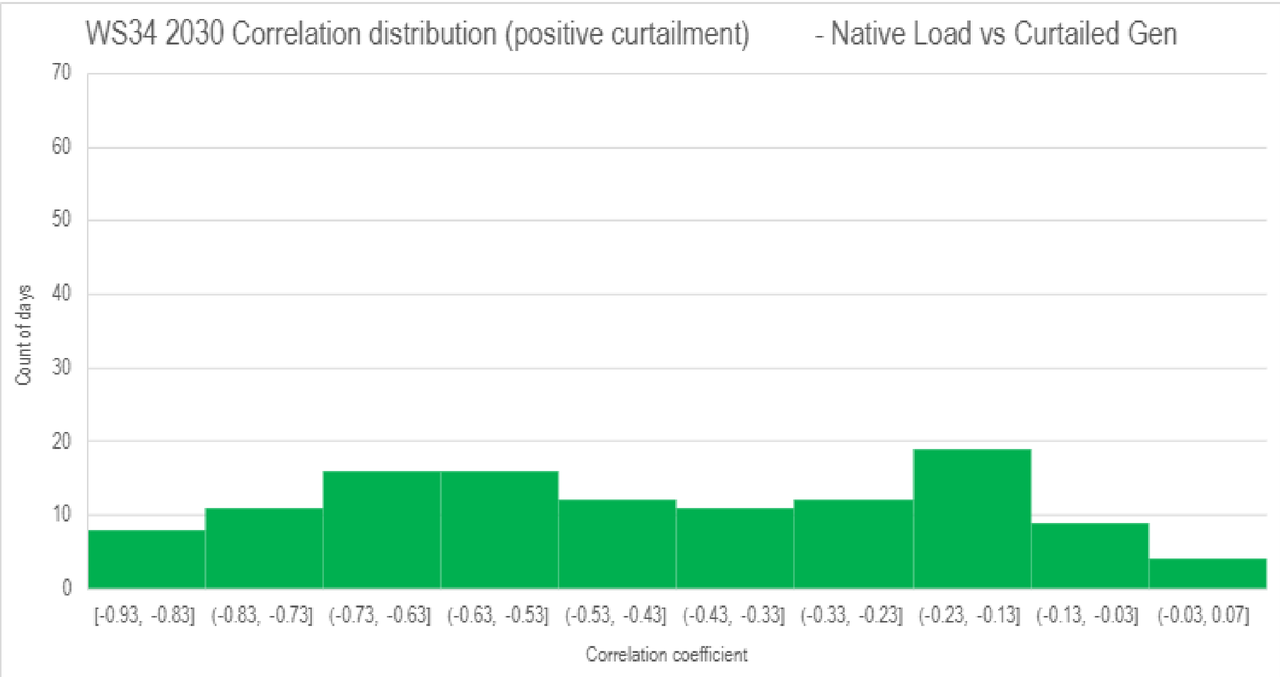


Figure 137: Correlation Distribution Native Load vs Curtailed Generation (as per the ACER Methodology requirement) (Positive curtailment), 2030, WS34 - Article 8(4)(d)



Appendix B.2.5 Article 16(1), 16(2), 16(3), 16(5)

Hourly

Figure 138: Hourly dispatch down for system vs transmission curtailment (MW), 2028, WS4 - Article 16(5)

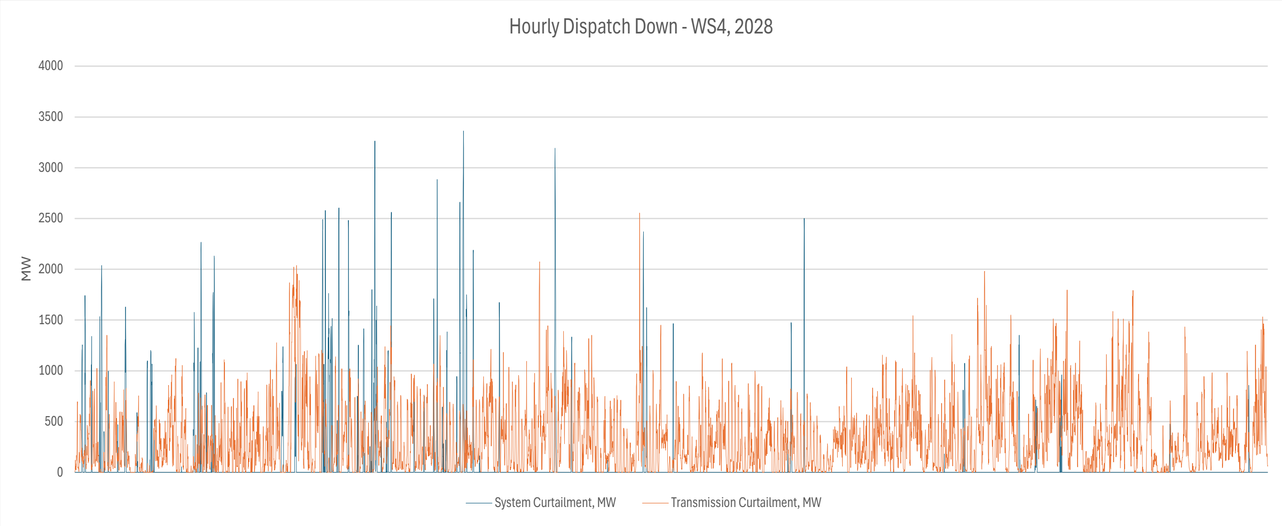


Figure 139: Hourly dispatch down for system vs transmission curtailment (MW), 2030, WS4 - Article 16(5)

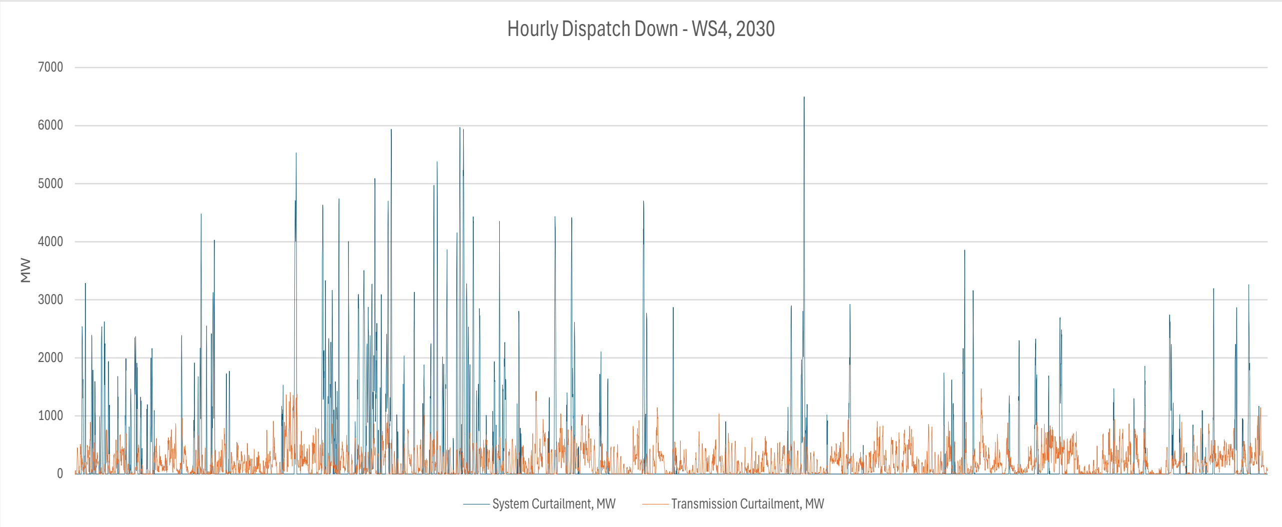


Figure 140: Hourly dispatch down for system vs transmission curtailment (MW), 2028, WS34 - Article 16(5)

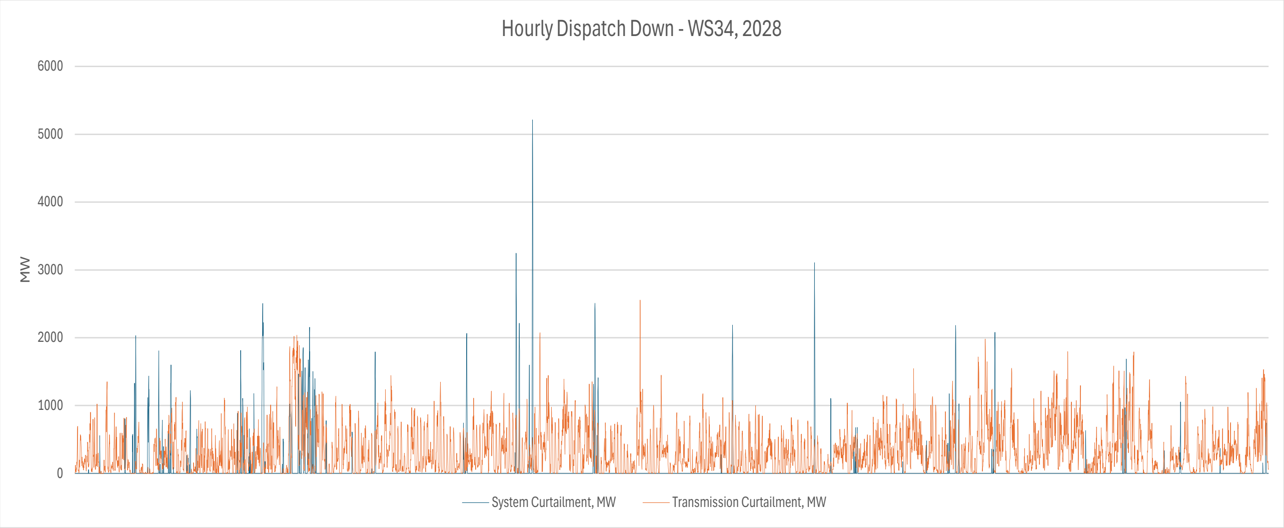
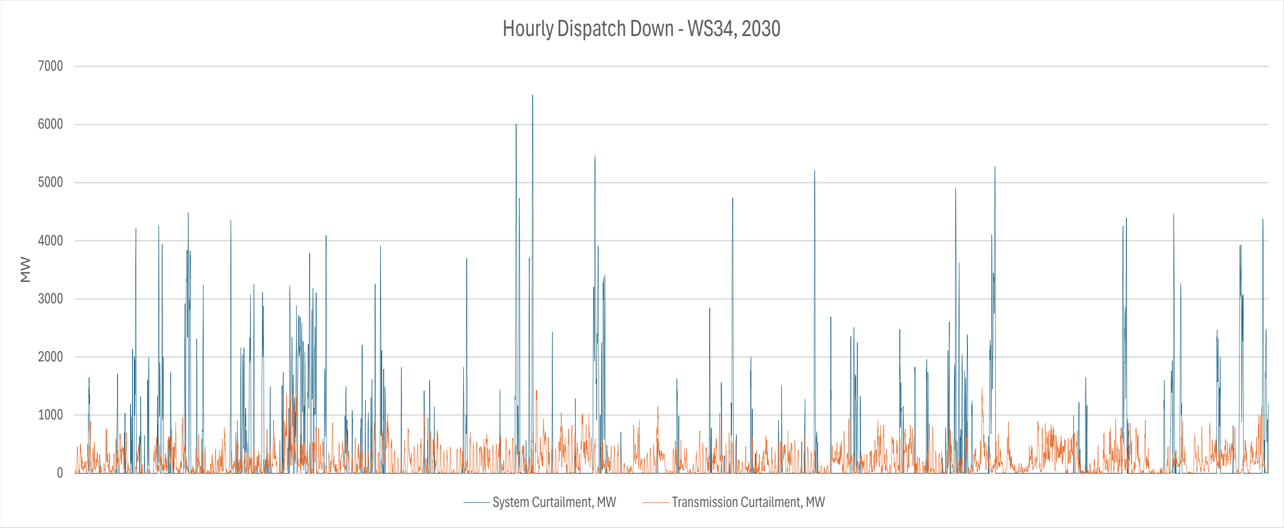


Figure 141: Hourly dispatch down for system vs transmission curtailment (MW), 2030, WS34 - Article 16(5)



Daily

Figure 142: Daily dispatch down for system vs transmission curtailment (MWh), 2028, WS4 - Article 16(5)

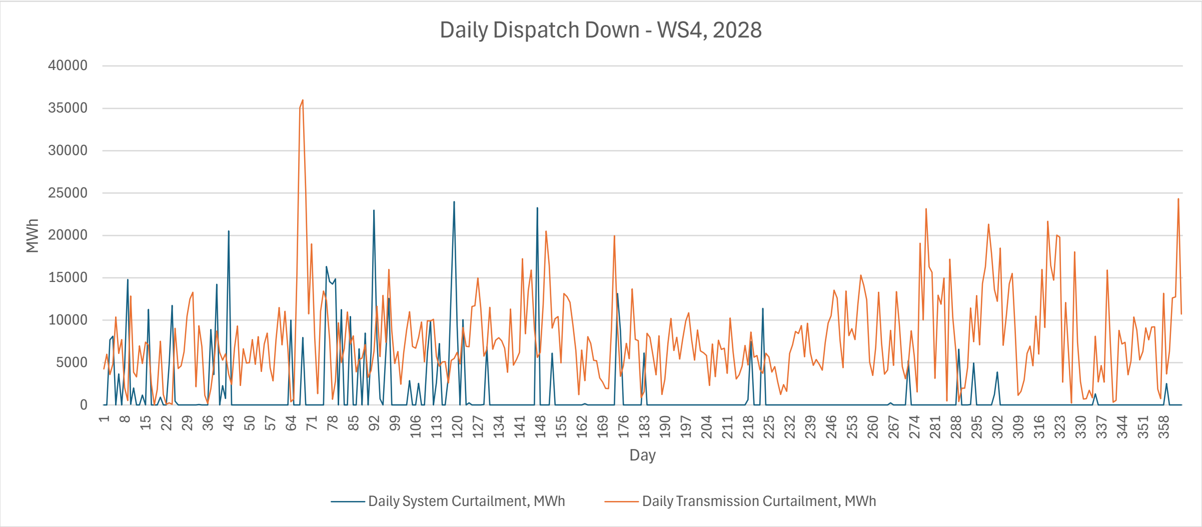


Figure 143: Daily dispatch down for system vs transmission curtailment (MWh), 2030, WS4 - Article 16(5)

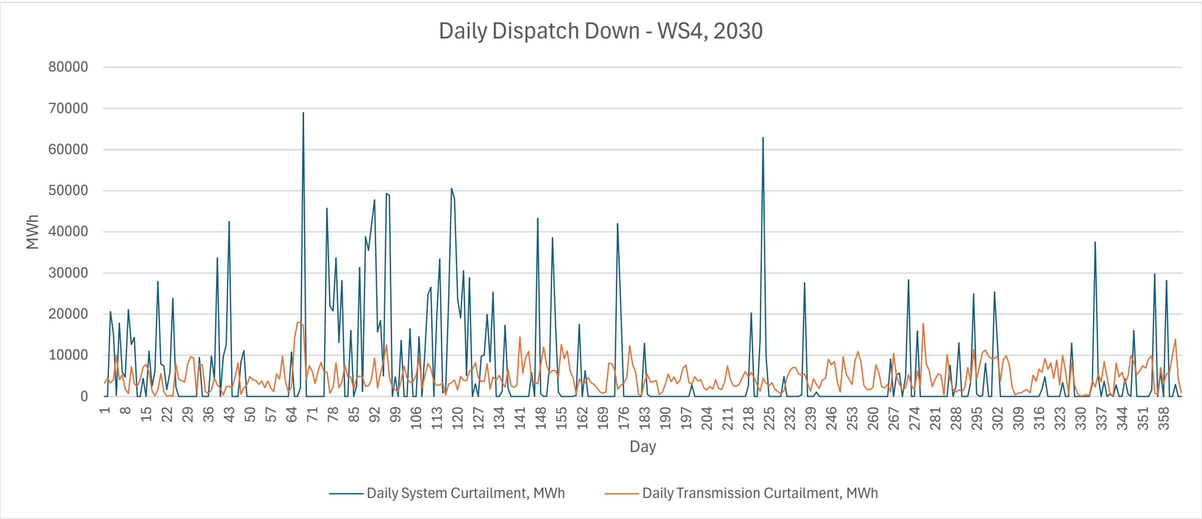


Figure 144: Daily dispatch down for system vs transmission curtailment (MWh), 2028, WS34 - Article 16(5)

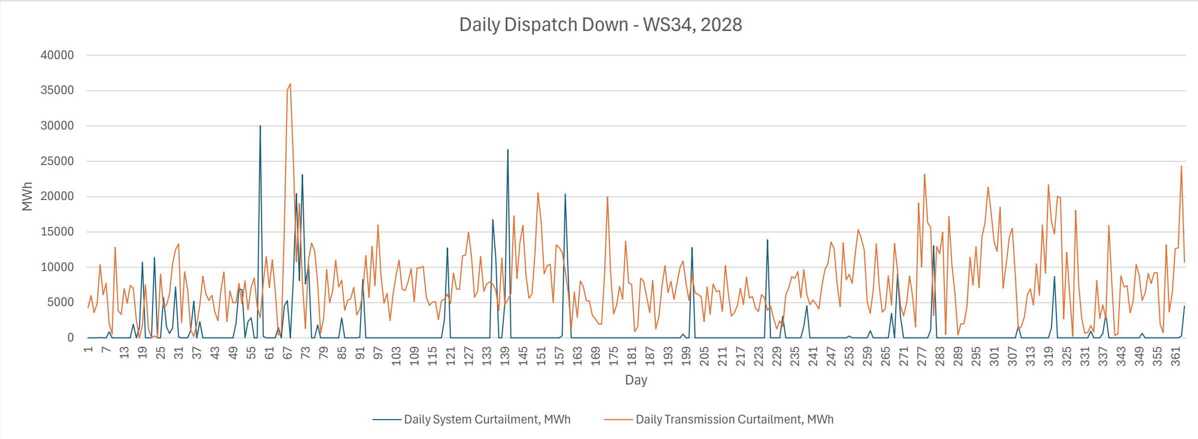
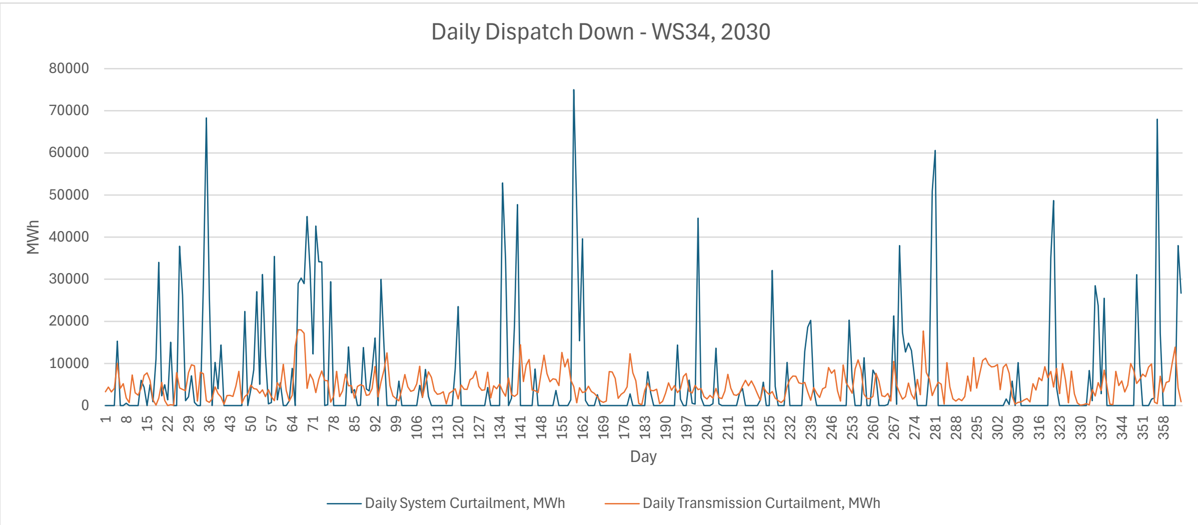


Figure 145: Daily dispatch down for system vs transmission curtailment (MWh), 2030, WS34 - Article 16(5)



Monthly

Figure 146: Monthly dispatch down for system vs transmission curtailment (MWh), 2028, WS4 - Article 16(5)

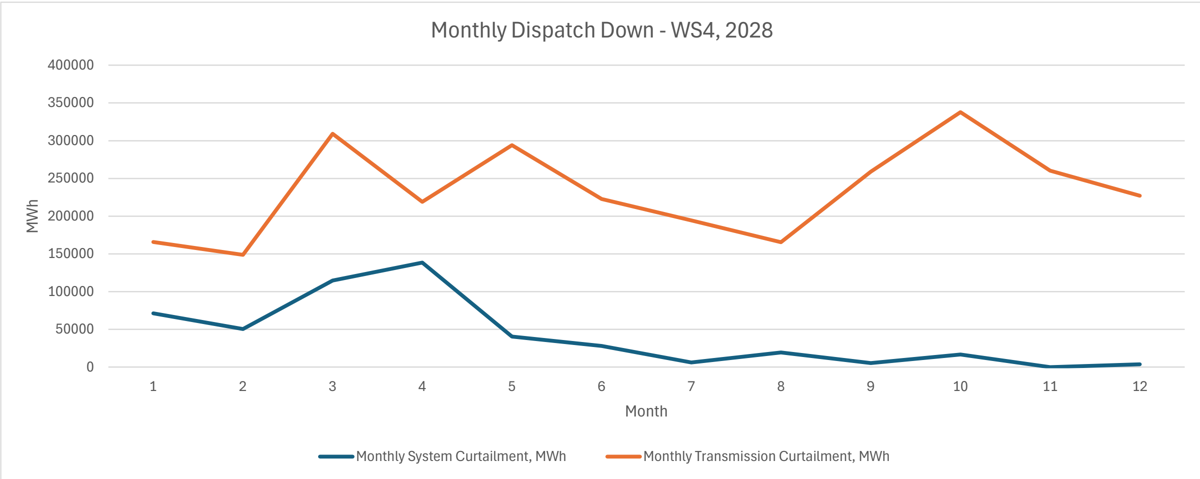


Figure 147: Monthly dispatch down for system vs transmission curtailment (MWh), 2030, WS4 - Article 16(5)

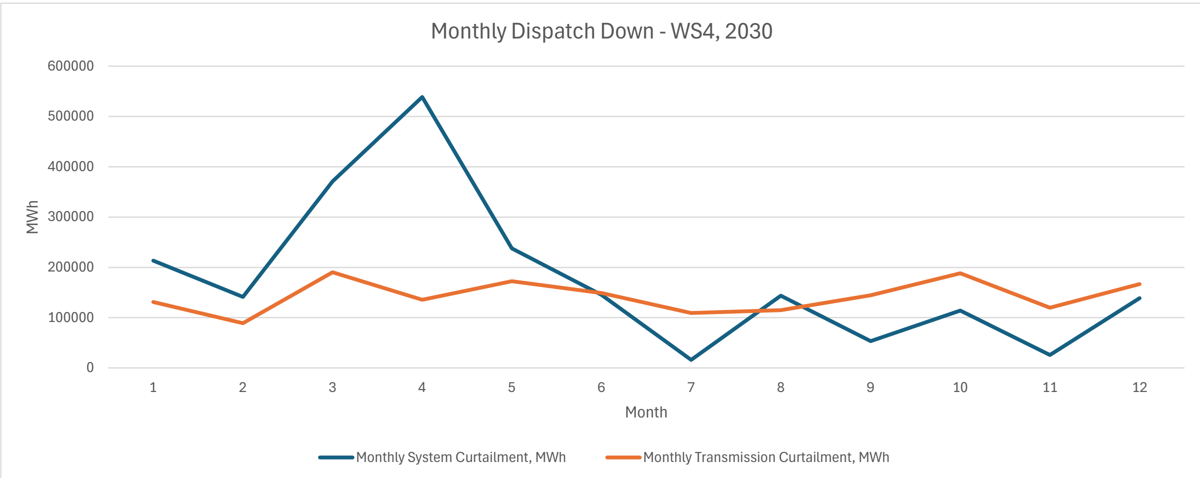


Figure 148: Monthly dispatch down for system vs transmission curtailment (MWh), 2028, WS34 - Article 16(5)

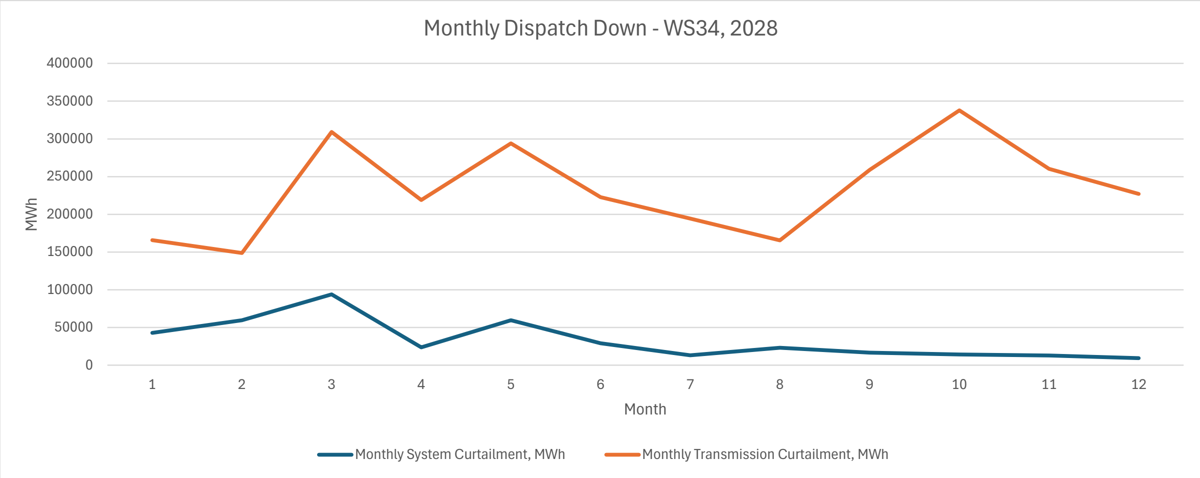
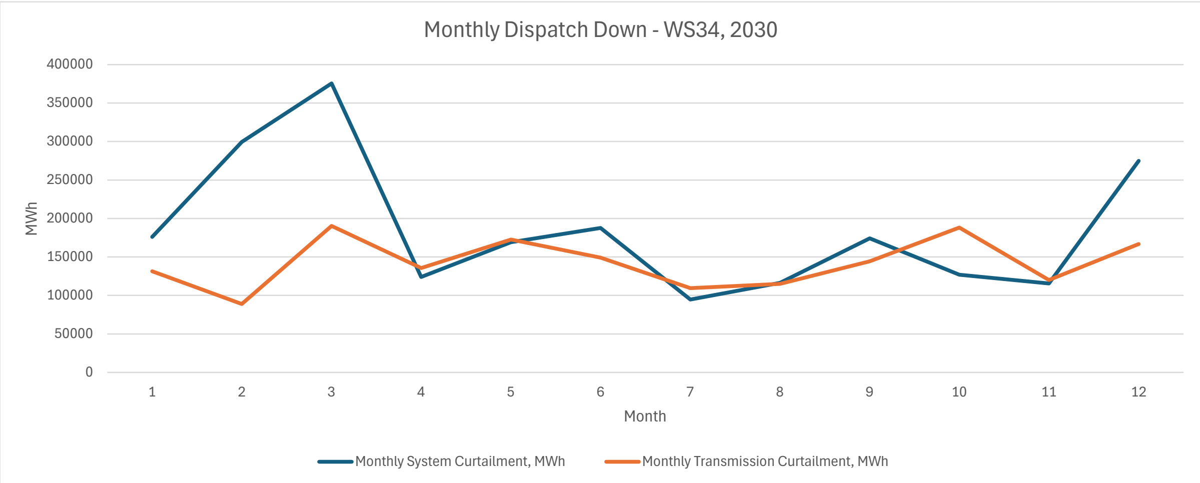


Figure 149: Monthly dispatch down for system vs transmission curtailment (MWh), 2030, WS34 - Article 16(5)



Appendix C – Distribution Level Needs – full zone and station level results

Details of the flexibility needs identified for each zone, and for the distribution stations within each zone, are provided in the spreadsheets linked below. A sample of the information provided is reproduced below for Collooney 38kV/MV station within Zone 3.

These graphs compare the loading profile for 2027/28 (Figure 150) and 2029/30 (Figure 151) (orange line) with the non-firm capacity limit (green line) at the station:

Figure 150: Collooney 38kV/MV station loading profile and non-firm capacity limit, 2027/28

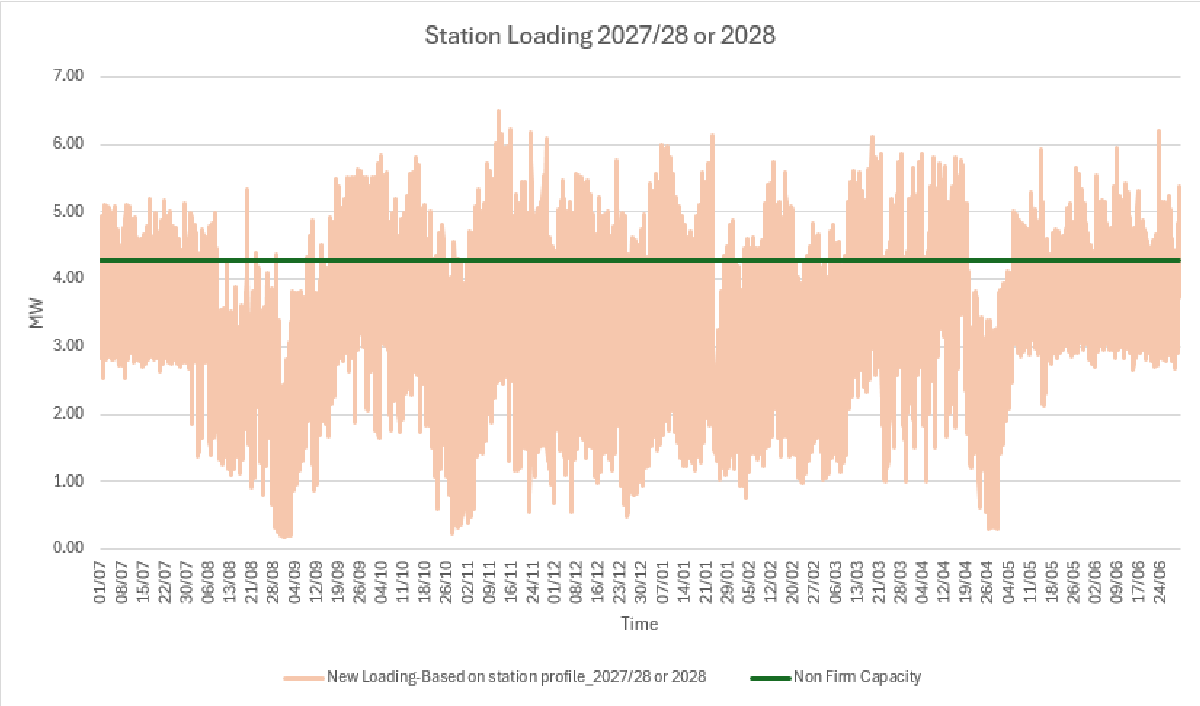
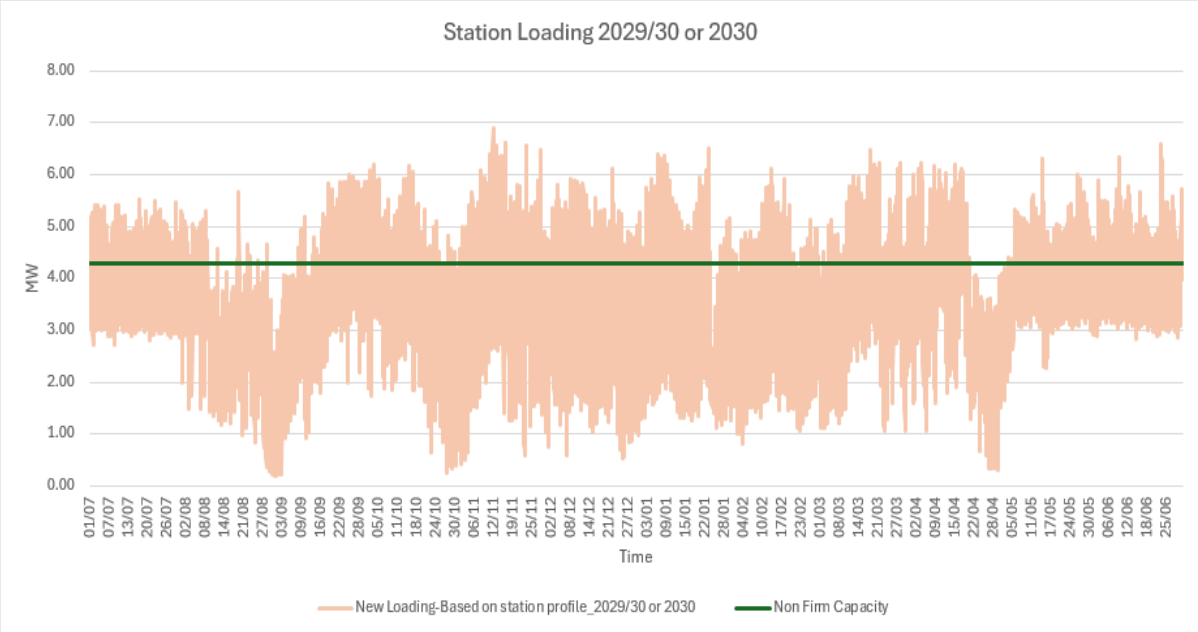


Figure 151: Collooney 38kV/MV station loading profile and non-firm capacity limit, 2029/30



In addition to the graphs above, for each station a number of tables are included. In line with the ACER Methodology document there is a table for each substation which includes the following detail (also set out in Table 35, Section 7.1):

- Direction of need (Upwards for all stations)
- Target Years: 2028 and 2030
- Time block: when the flexible need arises
- Reasoning to define the time block: Congestion at station level
- Spatial Granularity: station name
- Voltage level of congestion issue: for example, 38kV/MV
- Type of Value: Energy or power
- Network Flexibility needs: in MWh or MW
- Expected contractual means to access flexibility: procurement of flexible services or utilisation of flexible connection agreements

Additional tables are included representing the % of the count of half hourly intervals which have a flexibility requirement for both 2028 and 2030 target years.

For each station, two tables are provided across each target year:

- one for weekdays, and

- one for weekends

In total there are 4 tables across the target years of 2028 and 2030.

Appendix C.1 Zonal Spreadsheet Links:

Zone 3

Zone 4

Zone 5

Zone 6

Zone 7

Zone 8

Zone 9

Zone 10

Zone 11

Zone 12

Zone 13

Zone 14

Zone 15

Zone 16

Zone 17

Zone 19

Zone 20

Zone 21

Zone 22

Zone 23

Zone 24

Zone 25

Zone 26

Zone 27 (Dublin Central)

Zone 27 (Dublin North)

Zone 27 (Dublin south)

Appendix D – Distribution Level Needs – 110kV Hub assessment outcomes

Appendix D.1 List of stations and Hub Assessment Outcomes:

In accordance with the hub assessment methodology outlined in Section 4.1.7 of the Flexibility Needs Analysis Methodology Chapter, flexibility assessments have been completed for the stations listed below. Table 107 presents each parent station alongside its downstream stations where flexibility needs have been identified. Table 108 summarises the flexibility requirements at the parent 110/38kV station both before and after incorporating downstream contributions.

Table 107: 110kV/38kV and 38kV/MV stations assessed as part of the Hub Assessment

Zone	Parent Station	Downstream Stations
Zone 10	Somerset-110kV/38kV	Loughrea-38 kV/10 kV
Zone 16	Ikerrin-110kV/38kV	Roscrea-38 kV/10 kV, Rathdowney-38 kV/10 kV
Zone 16	Nenagh-110kV/38kV	Toomevara-38 kV/10 kV, Kyleeragh-38 kV/10kV
Zone 25	Midleton-110kV/38kV	Cloyne-38 kV/10 kV, Killacloyne-38 kV/10kV

Table 108: Flexibility Needs at the 110kV/38kV stations pre and post Hub Assessment

Station Names	Pre Hub Assessment		Post Hub Assessment		Comments
	MW - 2028/2030	MWh - 2028/2030	MW - 2028/2030	MWh - 2028/2030	
Somerset 110kV/38kV: [1*31.5MVA]	7.4 MW / -	231.0 MWh / -	4.7 MW / -	81.0 MWh / -	Downstream contributions substantially reduce upstream flexibility needs because the Loughrea 38 kV/10kV need is high and the timestamps are fully aligned.
Ikerrin 110 kV/38kV: [1*31.5MVA]	7.8 MW / 9.9 MW	884.0 MWh / 2058.01MWh	7.8 MW / 9.78 MW	881.0 MWh / 2035.64 MWh	Downstream contributions only minimally reduce upstream flexibility needs because the Roscrea 38 kV/10kV and Rathdowney 38 kV/10kV needs are small and the timelines are not fully aligned.
Nenagh 110 kV/38kV: [1*31.5MVA]	7.9 MW / 10.0 MW	206.0 MWh / 540.0 MWh	7.9 MW / 10.0 MW	205.0 MWh / 530.0 MWh	Downstream contributions only minimally reduce upstream flexibility needs because the Kyleeragh 38kV/10kV and Toomevara 38kV/10kV needs are small and the timelines are not fully aligned.
Midleton 110kV/38kV: [1*31.5MVA]	11.0 MW / -	7372.0 MWh / -	6.6 MW / -	3032.0 MWh / -	Downstream contributions substantially reduce upstream flexibility needs because the Cloyne 38kV/10kV and Killaclo yne 38kV/10kV needs are high, an d the timestamps are fully aligned.

Appendix E – Load Growth Rates

Table 109: Load Growth Rates

Planner Group	25-30 Peak Growth
ARKLOW	3.30%
ATHLONE	3.40%
BALLINA	2.50%
BANDON	3.70%
CASTLEBAR	2.40%
CAVAN	3.20%
CLONMEL	2.90%
CORK CITY	3.70%
CORK	3.70%
DROGHEDA	3.90%
DUBLIN CENTRAL	4.20%
DUBLIN NORTH	4.60%
DUBLIN SOUTH	4.00%
DUNDALK	4.00%
DUNMANWAY	3.70%
ENNIS	3.40%
ENNISCORTHY	2.90%
FERMOY	3.60%
GALWAY	3.00%
KILKENNY	2.60%
KILLARNEY	3.00%
KILLYBEGS	2.60%
LETTERKENNY	2.60%
LIMERICK	3.10%
LONGFORD	2.70%
MULLINGAR	4.10%
NEWCASTLEWEST	3.10%
PORTLAOISE	2.90%
ROSCREA	3.00%
SLIGO	3.10%
THURLES	3.00%
TIPPERARY	3.00%
TRALEE	2.70%
TUAM	2.80%
TULLAMORE	3.20%
WATERFORD	2.70%
NATIONAL AVERAGE	**3.60%**

Appendix F – Voltage Assessment

This document includes Voltage Curves for each of the three sample stations which were assessed to evidence the positive impact of upwards flexibility on low voltage.

As set out in the main report, these assessments were carried out on a small sample of stations where flexible needs were identified. The stations selected were all 38kV/MV and were a mix of stations in urban versus rural areas.

The stations selected were

a. Carrickmacross 38kV/MV from area Cavan (Zone 8)

b. Fermoy North 38kV/MV from area Fermoy (Zone 25)

c. Little Mills 38kV/MV from area Dundalk (Zone 7)

The cycle period for the analysis at each of the stations is as below.

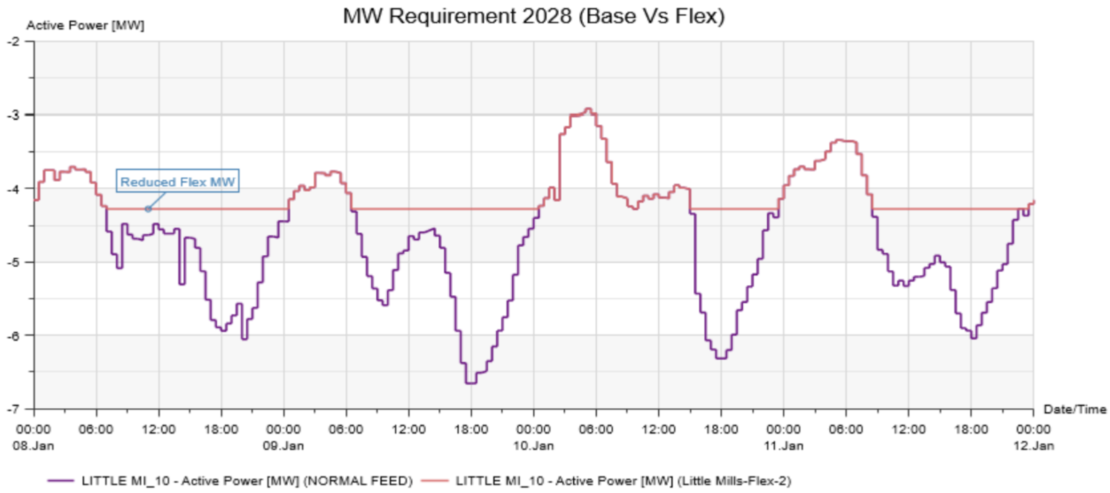
Table 110: Station Cycle Periods

Station	Target Year	Longest Required Duration	SINCAL Cycle Period
Fermoy North-38/MV	2028	19.5 hour [27/02/2028 05:00:00] - [28/02/2028 00:30:00]	26/02/2028-29/02/2028
	2030	No Requirement	No Requirement
Carrickmacross-38/MV	2028	2.5 hour [18/11/2027 16:00:00] - [18/11/2027 18:30:00]	17/11/2027-19/11/2027
	2030	5 hour [13/02/2030 08:30:00] - [13/02/2030 13:30:00]	12/02/2030-14/02/2030
Little Mills-38/MV	2028	18 hour [09/01/2028 06:30:00] - [10/01/2028 00:30:00]	08/01/2028-11/01/2028
	2030	20 hour [04/01/2030 07:00:00] - [05/01/2030 03:00:00]	03/01/2030-06/01/2030

Appendix F.1 Little Mills

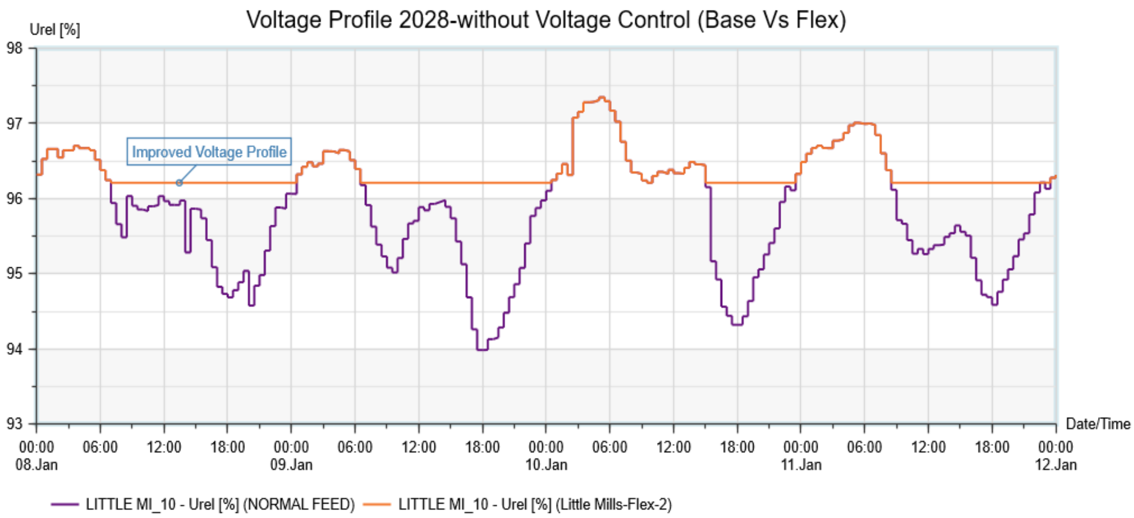
Little Mills 38kV/MV - 2028:

Figure 152: Load Profile – Little Mills 38kV/MV - 2028



The graph above shows the load at the station without any flexible services activated (purple) and with the flexible services activated (orange).

Figure 153: Voltage Profile – Little Mills 38kV/MV - 2028



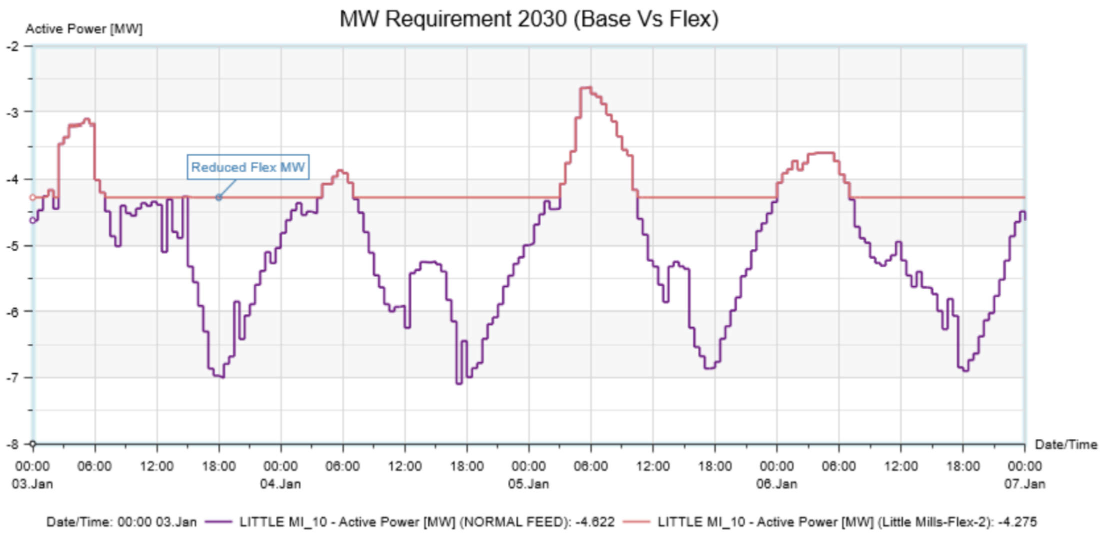
The second graph shows the voltage profile corresponding to the load profile. Once again, the voltage without flexible services activated is in purple. (It should also be noted that – for the purposes of the study – tap changers and boosters were switched to ‘OFF’. This was to ensure that we were seeing the explicit impact of upwards flexibility on the improvement of voltage profile.) The voltage profile where flexibility services were activated by the DSO is shown in orange.

It is evident that in the base loading scenario (purple line) the lowest voltage is approximately 94% of the nominal (equivalent to approximately 10.06kV). However, if it is assumed that required flexible services are procured and activated, then a voltage improvement is observed (lowest voltage is approximately 96.2% of the nominal - equivalent to approximately 10.2kV).

This result shows that procuring upwards flexibility has a positive impact on low voltage.

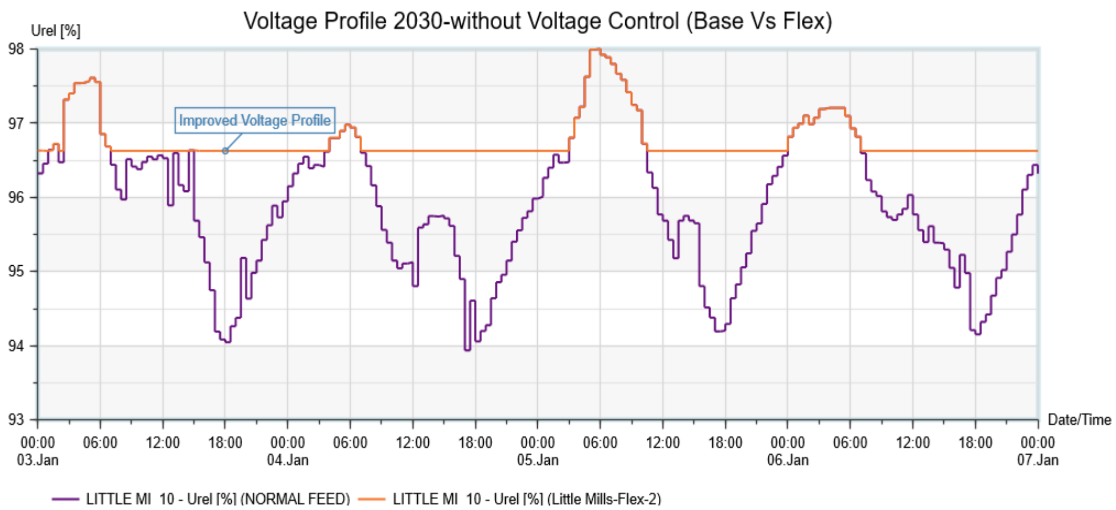
Little Mills 38kV/MV - 2030:

Figure 154: Load Profile – Little Mills 38kV/MV



The graph above shows the load at the station without any flexible services activated (purple) and with the flexible services activated (orange).

Figure 155: Voltage Profile – Little Mills 38kV/MV



The second graph shows the voltage profile corresponding to the load profile. Once again, the voltage without flexible services activated is in purple. (It should also be noted that – for the purposes of the study – tap changers and boosters were switched to 'OFF'. This was to ensure that we were seeing the explicit impact of upwards flexibility on the improvement of voltage profile.) The voltage profile where flexibility services were activated by the DSO is shown in orange.

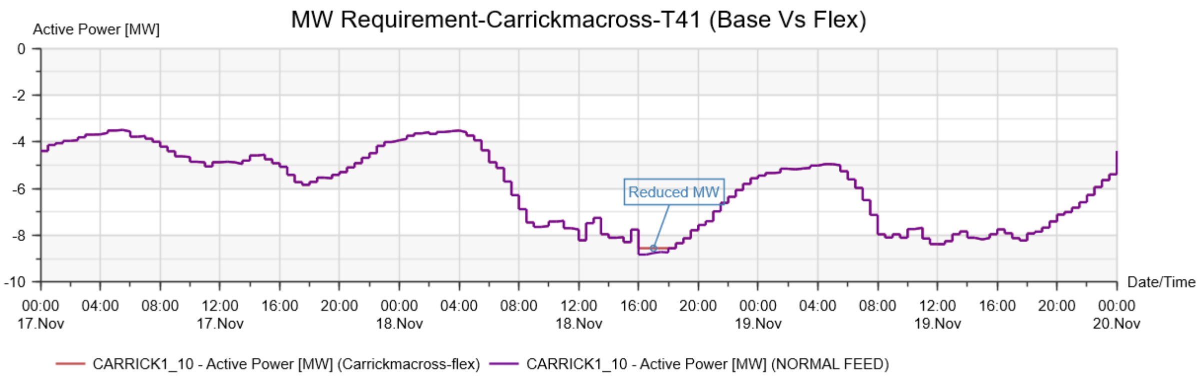
It is evident that in the base loading scenario (purple line) the lowest voltage is approximately 94% of the nominal (equivalent to approximately 10.06kV). However, if it is assumed that required flexible services are procured and activated, then a voltage improvement is observed (lowest voltage is approximately 97.5% of the nominal – equivalent to approximately 10.43kV).

This result shows that procuring upwards flexibility has a positive impact on low voltage.

Appendix F.2 Carrickmacross 38kV/MV

Carrickmacross 38kV/MV - 2028:

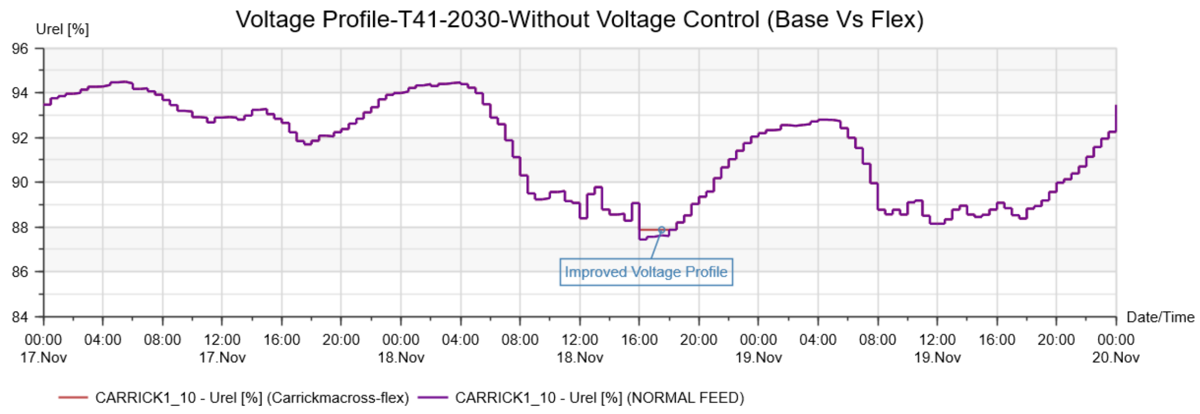
Figure 156: Load Profile – Carrickmacross 38kV/MV



The graph above shows the load at the T41[70] without any flexible services activated (purple) and with the flexible services activated (orange).

[70] The MW is for each transformer individually since these transformers are not being operated in parallel.

Figure 157: Voltage Profile – Carrickmacross 38kV/MV

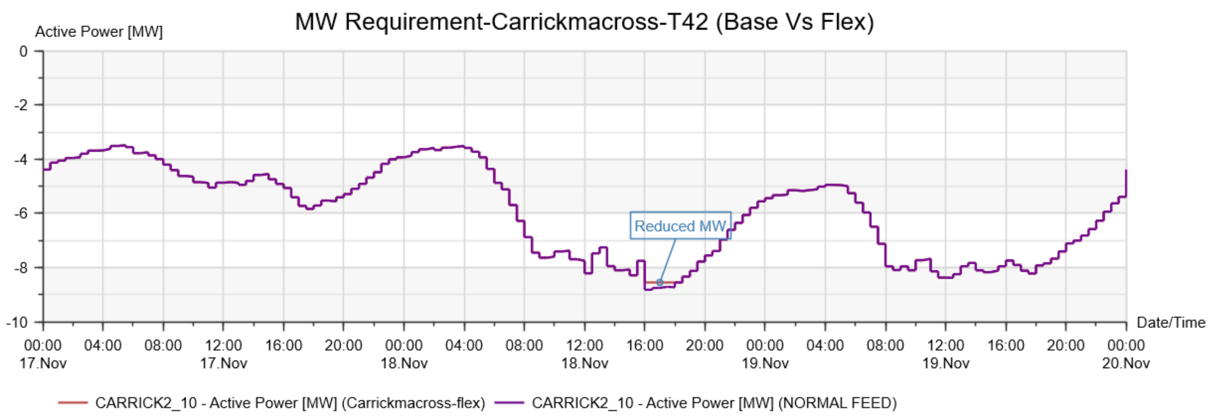


The second graph shows the voltage profile at T41 corresponding to the load profile. Once again, the voltage without flexible services activated is in purple. (It should also be noted that – for the purposes of the study – tap changers and boosters were switched to 'OFF'. This was to ensure that we were seeing the explicit impact of upwards flexibility on the improvement of voltage profile.) The voltage profile where flexibility services were activated by the DSO is shown in orange.

It is evident that in the base loading scenario (purple line) the lowest voltage is approximately 87% of the nominal (equivalent to approximately 9.30kV). However, if it is assumed that the required flexible services are procured and activated, a voltage improvement is observed (lowest voltage is approximately 88% of the nominal - equivalent to approximately 9.4kV).

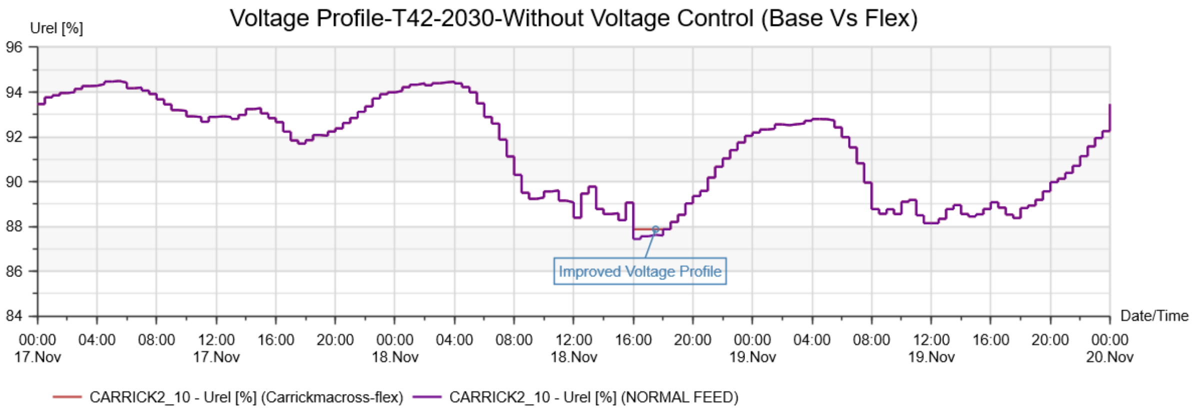
This result shows that procuring upwards flexibility has a positive impact on low voltage.

Figure 158: Load Profile – Carrickmacross 38kV/MV



The graph above shows the load at the T42 without any flexible services activated (purple) and with the flexible services activated (orange).

Figure 159: Voltage Profile – Carrickmacross 38kV/MV



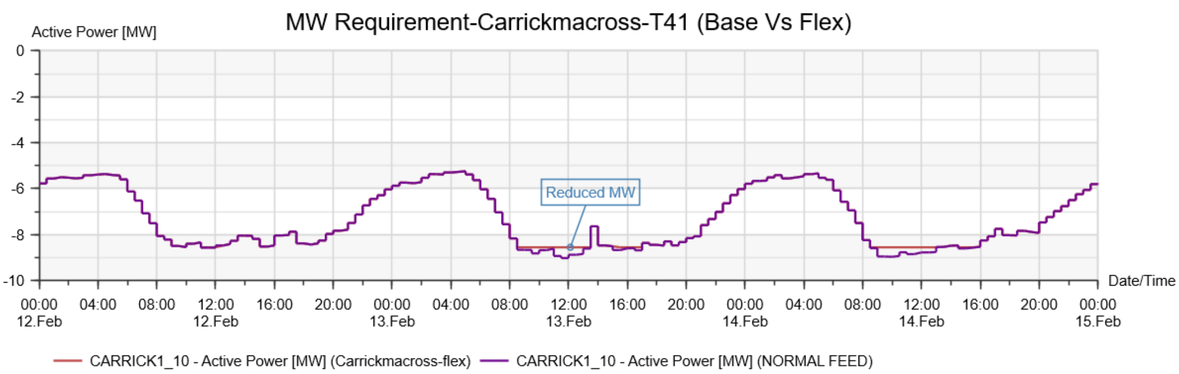
The second graph shows the voltage profile at T42 corresponding to the load profile. Once again, the voltage without flexible services activated is in purple. (It should also be noted that – for the purposes of the study – tap changers and boosters were switched to 'OFF'. This was to ensure that we were seeing the explicit impact of upwards flexibility on the improvement of voltage profile.) The voltage profile where flexibility services were activated by the DSO is shown in orange.

It is evident that in the base loading scenario (purple line) the lowest voltage is approximately 87% of the nominal (equivalent to approximately 9.30kV). However, if it is assumed that the required flexible services are procured and activated, a voltage improvement is observed (lowest voltage is approximately 88% of the nominal - equivalent to approximately 9.4kV).

This result shows that procuring upwards flexibility has a positive impact on low voltage.

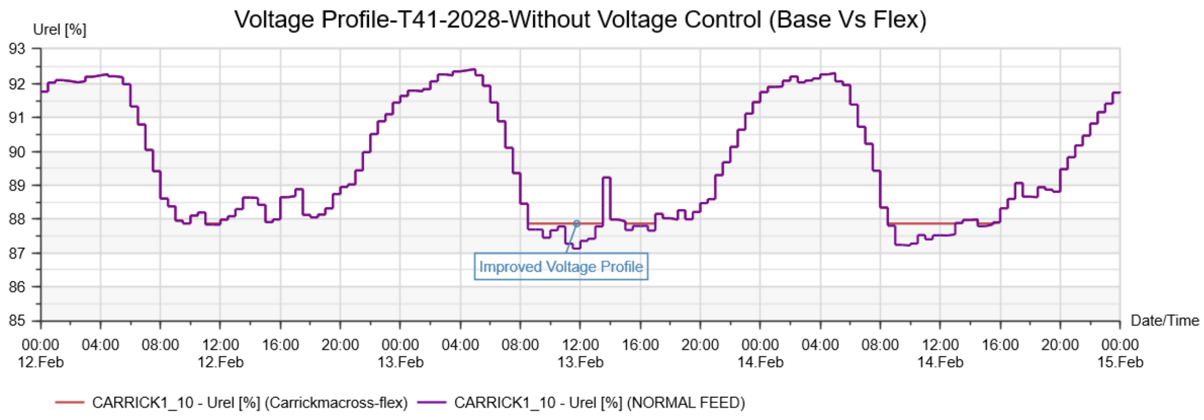
Carrickmacross 38kV/MV - 2030:

Figure 160: Load Profile – Carrickmacross 38kV/MV



The graph above shows the load at the T41 without any flexible services activated (purple) and with the flexible services activated (orange).

Figure 161: Voltage Profile – Carrickmacross 38kV/MV

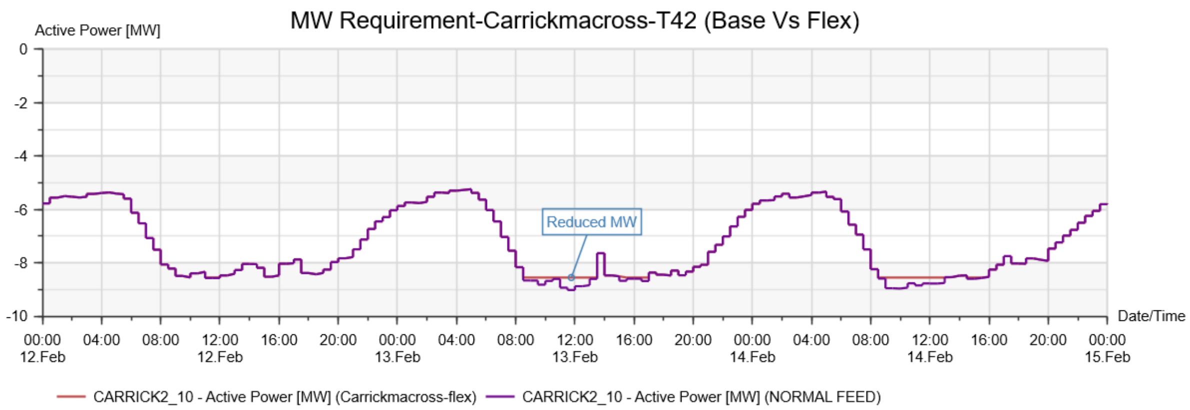


The second graph shows the voltage profile at T41 corresponding to the load profile. Once again, the voltage without flexible services activated is in purple. (It should also be noted that – for the purposes of the study – tap changers and boosters were switched to 'OFF'. This was to ensure that we were seeing the explicit impact of upwards flexibility on the improvement of voltage profile.) The voltage profile where flexibility services were activated by the DSO is shown in orange.

It is evident that in the base loading scenario (purple line) the lowest voltage is approximately 87.5% of the nominal (equivalent to approximately 9.336kV). However, if it is assumed that the required flexible services are procured and activated, a voltage improvement is observed (lowest voltage is approximately 88% of the nominal - equivalent to approximately 9.4kV).

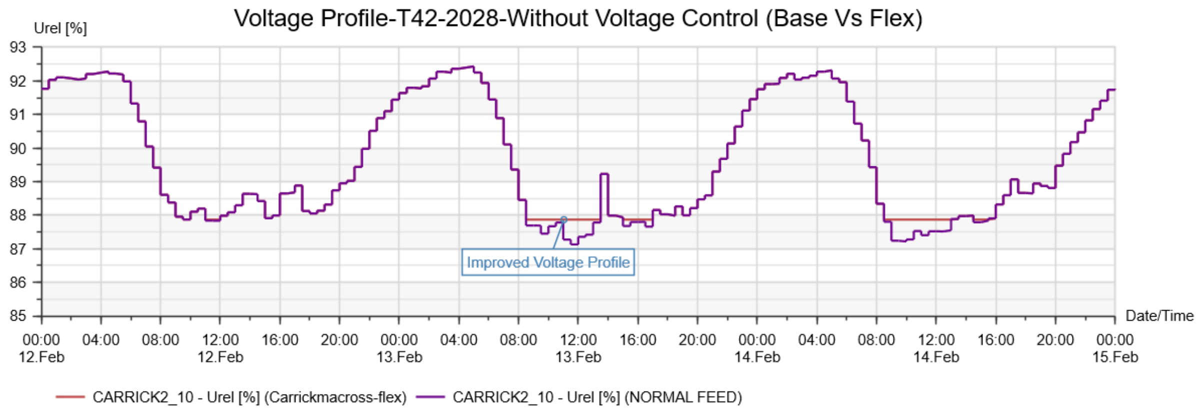
This result shows that procuring upwards flexibility has a positive impact on low voltage.

Figure 162: Load Profile – Carrickmacross 38kV/MV



The graph above shows the load at the T42 without any flexible services activated (purple) and with the flexible services activated (orange).

Figure 163: Voltage Profile – Carrickmacross 38kV/MV



The second graph shows the voltage profile at T42 corresponding to the load profile. Once again, the voltage without flexible services activated is in purple. (It should also be noted that – for the purposes of the study – tap changers and boosters were switched to 'OFF'. This was to ensure that we were seeing the explicit impact of upwards flexibility on the improvement of voltage profile.) The voltage profile where flexibility services were activated by the DSO is shown in orange.

It is evident that in the base loading scenario (purple line) the lowest voltage is approximately 87.5% of the nominal (equivalent to approximately 9.336kV). However, if it is assumed that required flexible services are procured and activated, a voltage improvement is observed (lowest voltage is approximately 88% of the nominal - equivalent to approximately 9.4kV).

This result shows that procuring upwards flexibility has a positive impact on low voltage.