Enduring Connection Policy 2.4

Solar and Wind Constraints Report: Assumptions and Methodology

Version 1.0

31/03/2025

EirGrid

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Revision	Date	Description

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List of Figures & Tables

1.1 Figures

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Document Structure

This document describes study assumptions and methodology. For customers wishing to see the estimated Total Dispatch Down for each area in the network, please see the individual area specific reports found on the ECP-2.4 webpage[1].

This document contains five main sections, three Appendices, an Abbreviations and Terms section and a Reference page. The structure of the document is listed below.

Section 1: Introduction: presents the purpose of the report and the definitions of surplus, curtailment, and constraint.

Section 2: Study Overview: introduces the study areas, the study years, and the generation scenarios. Together, these comprise the study scenarios.

Section 3: Study Input Assumptions: describes the study assumptions as they relate to network, demand, interconnection, generation, and system operational limits.

Section 4: Study Methodology: provides an overview of the software used and how the model is put together. A description of how Total Dispatch Down results are apportioned is also provided.

Section 5: Results Summary for Ireland: provides an overview of the reduction in renewable generation forecasted by this study at system level for Ireland.

Appendix A: Network Reinforcements: lists the reinforcements that are included in the study for each network scenario. These reinforcements have a material impact on the resulting constraints. This section also lists the representative transmission outage schedule included within the analysis.

Appendix B: Generator Details: provides an overview of the generation. It also provides a comprehensive list of the individual generators included in the study.

Appendix C: Contingencies and Lines Overloading: lists the main overload and contingency pairs binding for more than 200 hours for the 2027 and 2029 study years.

Abbreviations and Terms: provides a list of the abbreviations and terms used in the document.

References: provides a list of the documents referenced within the report.

[1] https://www.eirgrid.ie/industry/customer-information/ecp-constraint-forecast-reports#ecp-2.4-constraint-reports-for-solar-and-wind

Important Note

This ECP-2.4 constraints report presents an estimate of the reduction in available solar and wind generation based on the study assumptions described. The reduction in available generation has been split into three categories for the purposes of this study: surplus, curtailment, and constraint.

Following the Judicial decision on the SEM-22-009 Decision Paper on Dispatch, Redispatch and Compensation Pursuant to Regulation EU 2019/943, the detailed design for implementing Articles 12 and 13 is yet to be determined and may differ from the implementation for Total Dispatch Down used in this study. Therefore, an assumed interpretation will be used for ECP-2.4 Constraint Analysis that applies a grandfathering[2] approach to resolving Surplus and Constraint conditions. However, in addition to the Core ECP 2.4 constraint forecast studies a set of sensitivity studies are also included in the study scenarios which employs pro-rata allocation of constraints.

This report uses the term “Total Dispatch Down” to refer to the total reduction in available solar and wind generation i.e., the sum of surplus, curtailment, and constraint, and is considered the key indicator for the results. However, it is important to note that the term “dispatch down” is more correctly applicable only to TSO instructions to reduce generation output from a market position, as is the case for curtailment and constraint, and is not necessarily applicable to a generator reducing its own output from its availability to a market position so that supply and demand are balanced, as is the case for surplus.

The results presented in this report are based on the simulation and modelling assumptions described. The findings are indicative only and this report should in no way be read as a guarantee as to future levels of surplus, curtailment, and constraint.

The battery sensitivity is termed as “ECP Battery”, in which the non-connected batteries from the ECP scenario has been removed.

[2] ‘Grandfathering’ is where an old rule continues to apply to some existing situations while a new rule will apply to future cases. In the context of Article 12 and Article 13, grandfathering refers to the distinction between how priority dispatch renewable generators (those installed prior to 4th July 2019) and non-priority dispatch renewable generators (those installed on and after 4th July 2019) are treated in the SEM.

1 Introduction

1.1 Objective

It is a requirement of CRU's ECP-2 decision, CRU/20/0604[3], that the Transmission System Operator (TSO) carry out system studies to inform applicants about possible generation constraint levels in Ireland. EirGrid will complete this requirement across twelve regional reports. The purpose of the regional reports is to provide generation developers with information on possible levels of generation output reduction for a range of scenarios.

The reports present results for a range of generation scenarios and indicate the levels of Total Dispatch Down that solar and wind generation might experience in the future, where Total Dispatch Down is defined as in Figure 1-1.

Total Dispatch Down[4] = Surplus + Curtailment + Constraint

Figure 1-1 Total Dispatch Down Equation

The nodal level surplus, curtailment, and constraint results for each of the twelve study areas can be found in the individual area reports[5].

1.2 Background

The core study years for this analysis are 2027 and 2029. A further sensitivity study considers a Future Grid study horizon that aligns with the version of SOEF 1.1 Roadmap[6]. The details of transmission reinforcement projects included in each study horizon are included in Appendix A of this report.

The evaluation of Total Dispatch Down is impacted by a range of assumptions: generation, demand, interconnection, network, and operational limits. A summary of each of these is provided below. More detail on these study assumptions is provided in Section 2.

1.2.1 Generation

The Enduring Connection Policy (ECP) 2.4 is the fourth batch of connection offers planned under ECP-2 by the Commission for Regulation of Utilities (CRU) to facilitate opportunities for connections of Renewable Energy Sources (RES) on to the Irish electricity network. This report includes the 3.8 GW of generation,

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[3] https://cruie-live-96ca64acab2247eca8a850a7e54b-5b34f62.divio-media.com/documents/CRU20060-ECP-2-Decision.pdf

[4] For the purposes of this report, the term "Total Dispatch Down" includes surplus. Note however that "dispatch down" more correctly refers to dispatch away from a market position and as such, includes curtailment and constraint but not necessarily surplus.

[5] https://www.eirgrid.ie/industry/customer-information/ecp-constraint-forecast-reports#ecp-2.4-constraint-reports-for-solar-and-wind

[6] See link: https://www.eirgridgroup.com/site-files/library/EirGrid/Shaping-Our-Electricity-Future-Roadmap_Version-1.1_07.23.pdf

processed under the fourth of these batches - ECP-2.4. The corresponding area reports present the Total Dispatch Down results for wind and solar generation only.

It is not clear at this stage which generators will be successful in future renewable support auctions or other funding mechanisms, therefore the timing and location of future generation is uncertain. For this reason, results for various renewable generation scenarios are presented in the corresponding area reports.

1.2.2 Demand

The system demand forecast used in the 2027, 2029 and Future Grid ECP-2.4 constraints analysis is the median demand forecast from the All-Island Resource Adequacy Assessment (AIRAA) 2025 - 2034[7] for the respective years.

1.2.3 Interconnection

In addition to the existing Moyle, East-West (EWIC) and Greenlink interconnectors, the following future HVDC interconnectors have also been assumed:

- 700 MW Celtic HVDC interconnector to France – has been assumed in service for the 2029 and Future Grid study years.
- 700 MW LirIC HVDC interconnector to Great Britain – has been assumed in service for the Future Grid study year.
- 700 MW 2nd Ireland - France HVDC interconnector – has been assumed in service for the Future Grid study year.

In addition to the existing North-South HVAC interconnector between Louth and Tandragee, the second North-South HVAC interconnector between County Tyrone and County Meath is included for the 2029 and Future Grid study horizons. These dates are in accordance with publication of Network Delivery Portfolio (NDP)[8] in Q3 of 2024.

1.2.4 Network

The network reinforcement assumptions used for the core 2027 and 2029 study horizons are aligned with the current estimated delivery dates for existing reinforcement projects, these dates have been sourced from EirGrid's latest NDP (Q3, 2024).

The network assumed for the Future Grid study horizon is aligned with the SOEF 1.1 Roadmap network assumptions. Further, any update in the NDP list of projects with respect to SOEF 1.1 Roadmap is updated for the Future Grid study. List of reinforcement included in each study is year is included in Appendix A of this report.

1.2.5 Operational Limits

The operational limits are derived from the Operational Policy Roadmap 2025 - 2035 , the TSO Imperfections and Constraints Multi-year Plan 2024 – 2028 and are aligned to the SOEF 1.1 Roadmap where applicable.

Under the SOEF 1.1 Roadmap, the system operation workstream sets out a plan for further developing our operational capability to facilitate increased levels of wind and solar generation. This includes the evolution of operational parameters such as: System Non-Synchronous Penetration (SNSP), Rate of Change of Frequency (RoCoF), inertia, minimum number of conventional units and system service provision from new, low- carbon sources. These system operational roadmap assumptions are included in section 3.11.2.1 of this report.

[7] https://cms.eirgrid.ie/sites/default/files/publications/AIRAA-2025-2034.pdf
[8] https://cms.eirgrid.ie/sites/default/files/publications/Network-Delivery-Portfolio-Publication-Q3-2024.pdf

1.3 Definition of Surplus, Curtailment and Constraint

The assumed interpretation of Article 12 and Article 13 that will be modelled in ECP-2.4 constraints analysis is outlined below for each category of dispatch down namely surplus, curtailment, and constraints.

1.3.1 Surplus

The reduction of available renewable generation for surplus reasons is necessary when the total available generation exceeds system demand plus interconnector export flows. In this study, generation reduction for surplus is applied prior to curtailment and constraint.

Under the EU's Clean Energy Package, it has been mandated that priority dispatch of renewable generation will continue to apply only to generators which connected prior to 4th July 2019 (Article 12). This will create a new type of generator for consideration in the dispatch process – the non-priority dispatch renewable generator, connected post 4th July 2019.

For this study it has been decided to use the operational enduring arrangement outlined in SEM-22-009, which is the same approach used within the ECP-2.3 constraints analysis. This approach is summarised below.

During generation reduction for surplus reasons, a distinction is made between the treatment of priority and non-priority renewable generators, and non-priority generators are reduced ahead of priority generators. Within these two categories of generation, surplus is applied pro-rata across the all-island system for all generators in the category.

1.3.2 Curtailment

In order to operate a safe and secure electricity system, the TSO must operate the system within certain operational limits. These limits include:

- Maximum level of System Non-Synchronous Penetration (SNSP).
- Maximum Rate of Change of Frequency (RoCoF).
- Minimum level of system inertia.
- Minimum number of conventional units for stability.
- Minimum levels of reserve.
- Conventional generator "must run" rules to ensure adequate system voltage and power flow control.

Curtailment is applied to reduce the output of renewable generators in order to ensure that operational limits are not breached, and the system can remain secure and stable. Curtailment is applied to all renewable generators across the SEM (Single Electricity Market) on a pro-rata basis with no distinction made between the treatment of priority and non-priority generators. This approach is consistent with the ECP-2.3 methodology.

1.3.3 Constraint

The TSO plans the transmission system according to the Transmission System Security and Planning Standards (TSSPS)[9] as such generators may need to be dispatched down due to transmission network limitations and, in particular, to ensure that the thermal overload limits of transmission circuits and transformers are not breached. Therefore, we aim to reflect this in our modelling.

[9] https://cms.eirgrid.ie/sites/default/files/publications/EirGrid-Transmission-System-Security-and-Planning-Standards-TSSPS-Final-May-2016-APPROVED.pdf

Transmission equipment may become overloaded in an intact network or for network contingencies, where a line may become overloaded if another line were to trip. In order to avoid post fault overloads, renewable generation may be dispatched down.

Changes in generator output for this reason are referred to as a 'constraint'. The constraining of generation is location-specific and can be reduced, for example, by transmission network reinforcements. The model accounts for N-1 contingencies, this means that the system will be dispatched in such a way that any single contingency will not cause overloads.

Many a time there are multiple contingencies affecting an area. In such cases a constraint group is formulated, and constraints are shared among the group.

In this report, two approaches are used to allocate constraint-based dispatch down for each study. Firstly, with grandfathering (GF) of constraints, all non-priority dispatch units contributing to a *Constraint* problem will reduce output on a pro-rata basis. If a *Constraint* is unresolved by non-priority dispatch unit reduction alone, priority dispatch units contributing to the Constraint will also reduce output on a pro-rata basis. This grandfathering approach is similar to how market Surplus is resolved in ECP 2.4 modelling.

In the pro-rata constraints allocation, all priority and non-priority units are dispatched down on a pro-rata basis at relevant nodes to manage the network constraints. This method is applied to the relevant sensitivity scenarios.

2 Study Overview

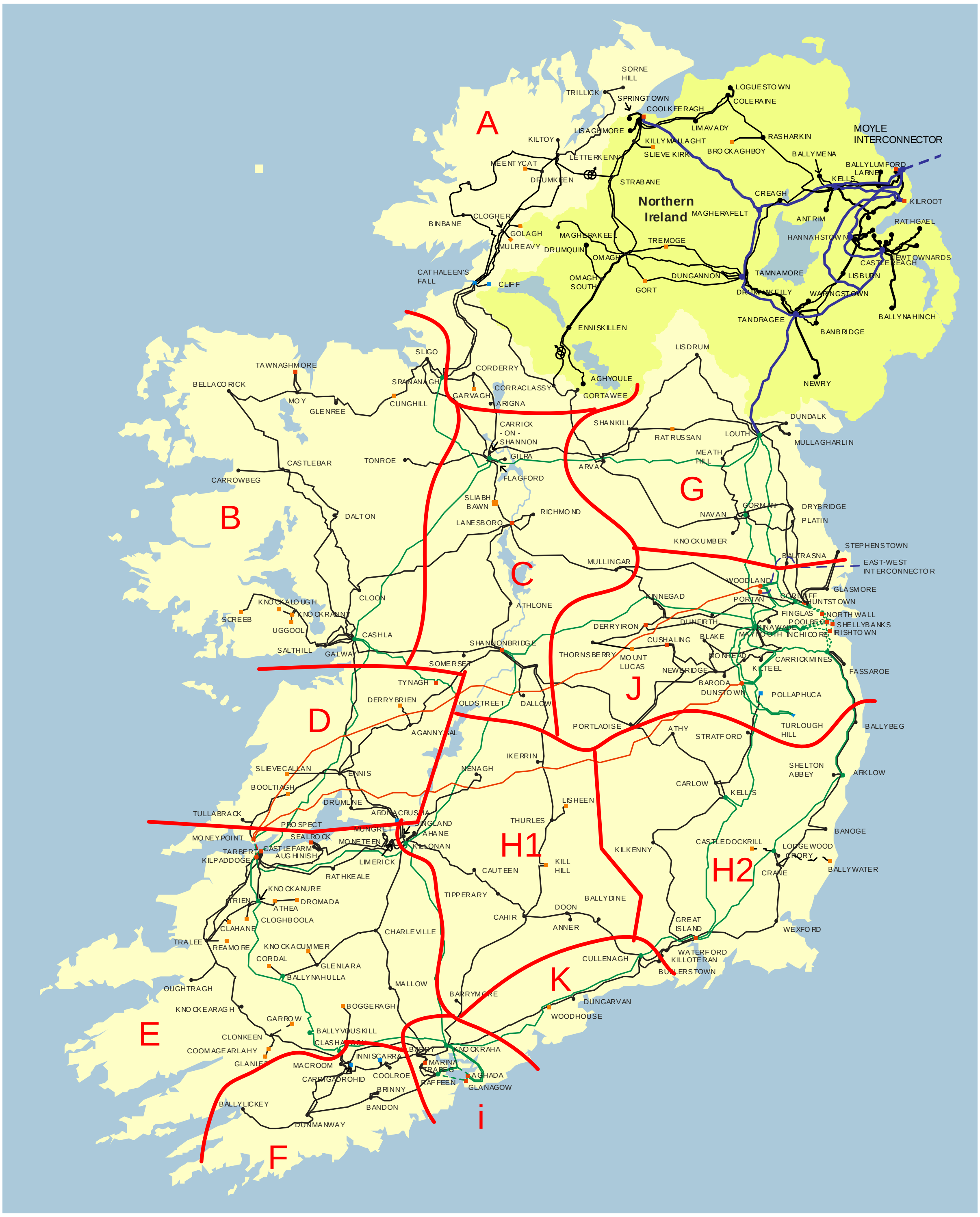

Figure 2-1 Areas Designated for Preparing Wind Energy Profiles, Generation Scenarios and Reporting Results

This section provides descriptions of the study scenarios which are a combination of generation scenarios and network study years.

An overview of the study areas is also provided. These are fundamental to understanding the contents of the individual area reports. It also provides an overview of the demand, generation and network assumptions that are used in the study. Taken together this information provides an overview of the ECP-2.4 constraint forecast analysis.

2.1 Study Areas & Year

The areas shown in Figure 2-1 are used for preparing wind energy profiles, for setting up generation scenarios and for reporting results. These areas are similar to those used in the previous constraints analysis.

The study years are chosen to capture expected progress over the short to medium term regarding predicted operational limitation improvements, transmission reinforcements and forecast demand increase.

This is achieved by studying the years 2027 and 2029. For the years 2027, 2029, and Future Grid, the median demand forecast from EirGrid and SONI's All-Island Resource Adequacy Assessment (AIRAA) is used.

During previous consultations with industry, there was request for further sensitivity studies considering the impact of the Shaping Our Electricity Future (SOEF) 1.1 Roadmap. Hence, a Future Grid scenario has also been studied, this scenario has the network and operational constraint assumptions aligned with the SOEF 1.1 Roadmap. Please note, any references to the 2030 study year in this report relate to the Future Grid scenario.

2.2 Study Scenarios

Studies were carried out for several study years with different network assumptions, and generation scenarios. An overview of the study scenarios can be seen in Figure 2-2.

The core ECP-2.4 study scenarios are marked green and grouped in Figure 2-2 and cover the years 2027 and 2029. In 2027, the base case for resolving surplus and constraint conditions is the pro-rata approach, whereas in 2029, it is the grandfathering approach. The RES generation capacities in the initial study include all renewable generation currently connected, plus all renewable generation scheduled to connect before the end of 2026. The 50% generation scenario is formulated by adding half of the difference between the initial and ECP scenarios to the initial study. The ECP generation scenario includes all the RES generation in the pipeline up to and including ECP-2.4 applicants (some of whom may not have received offers at this point in time but are still considered within these studies).

Following requests through the modelling assumptions engagement with industry, a number of sensitivity studies have been included as part of the analysis in addition to the core study scenarios. As a result of this, several sensitivity scenarios were developed, these include:

- Sensitivity studies based upon the SOEF 1.1 Roadmap (Future Grid) network.
- Multiple sensitivities considering the impact of the connection of offshore wind, batteries, and new interconnectors.
- A sensitivity study to show the impact of the representative maintenance schedule.

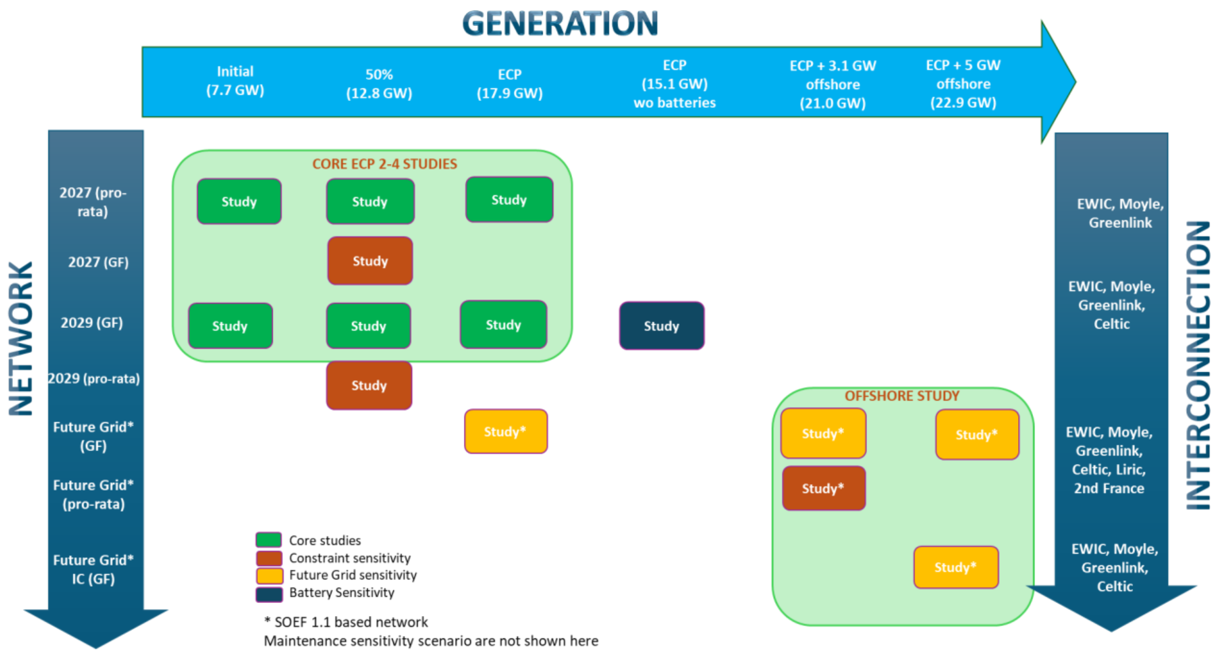

Figure 2-2 Study Scenarios: Matrix of Generation and Network Scenarios

The above figure contains the assumed total installed capacities (GW) in Ireland, which include wind, offshore wind, solar PV, and battery capacities for Ireland for the various scenarios.

2.3 Renewable Generation Scenarios

The three core generation scenarios are summarised below:

- The "Initial" scenario includes all renewable generation currently connected plus all Gate 3, non-GPA, ECP-1, ECP-2.1, ECP-2.2, ECP-2.3, and ECP-2.4 renewable generation scheduled to connect before the end of 2026.
- The "50%" generation scenario is formulated by adding half of the difference between the initial and ECP scenarios to the initial study.
- The "ECP" scenario includes all renewable generation currently connected plus all Gate 3, non-GPA, ECP-1, ECP-2.1, ECP-2.2, ECP-2.3, and ECP-2.4 renewable generation applications (some of whom may not have received offers at this point in time but are still considered within these studies).

Based on industry request, a battery sensitivity study has been included, which contains all renewable generations as in the ECP study scenario with non-connected batteries removed.

During previous consultations with industry, there was request for further sensitivity studies considering the impact of offshore wind to be included in the study scope. As a result of this, in the ECP-2.3 constraint forecast two additional offshore generation scenarios were developed the: "ECP + 3.1 GW offshore" and "ECP + 5 GW offshore". The ECP-2.4 constraint forecast has maintained these scenarios.

The two offshore generation scenarios are summarised below:

- The "ECP + 3.1 GW offshore" scenario includes all renewable generation in the "ECP" scenario plus an additional 3.1 GW of offshore wind.
- The "ECP + 5 GW offshore" scenario includes all renewable generation in the "ECP" scenario plus an additional 5 GW of offshore wind.

Offshore wind of 3.1 GW has been modelled within the analysis to align with the volume of successful offshore generation in the recent ORESS 1 auction. The 5 GW offshore assumption aligns with the volume of offshore within the SOEF 1.1 Roadmap.

All studies include a representative maintenance schedule. A maintenance sensitivity scenario based on the ECP generation, and the Future Grid network is also included (not shown in the figure). The maintenance sensitivity removes the representative maintenance schedule from the model and compares the results to the core ECP study (which includes the representative maintenance schedule).

A variety of renewable generation scenarios are included to take account of the possibility that not all generators will ultimately connect, and to give a view on the Total Dispatch Down seen under various renewable generation build out rates.

The results for each generation scenario are presented explicitly for each area in their respective area report.

2.4 Study Sensitivities

The study sensitivities across the 2027 and 2029 are presented as follows:

- 2027: 50% scenario (constraint allocation based on grandfathering).
- 2029: 50% scenario (constraint allocation based on pro-rata), ECP scenario without batteries (constraint allocation based on grandfathering).
- 2029: ECP battery sensitivity has all installed wind and solar as of 2029 ECP scenario but without the non-connected batteries.

The study sensitivities in the future grid are presented as follows:

- ECP scenario (constraint allocation based on grandfathering).
- ECP scenario + 3.1 GW offshore (constraint allocation based on grandfathering).
- ECP scenario + 3.1 GW offshore (constraint allocation based on pro-rata).
- ECP scenario + 5 GW offshore (constraint allocation based on grandfathering).
- ECP scenario + 5 GW offshore with interconnector sensitivity, i.e., without LirIC and 2nd France interconnector (constraint allocation based on grandfathering).

3 Study Input Assumptions

This section provides an overview of the input assumptions for the surplus, curtailment, and constraint modelling.

3.1 Valid for these Generation Assumptions

The estimated surplus, curtailment and constraint levels in this report are valid for the generation assumptions used in these studies.

3.2 All-Island Model

As ECP-2.4 is an Ireland connection process, this report provides estimates of surplus, curtailment, and constraint levels for Ireland and not for Northern Ireland. However, for this study, the all-island system including Ireland and Northern Ireland has been modelled in PLEXOS. This is necessary in order to provide a better estimate of generation reduction levels, given that both surplus and curtailment are all-island issues.

3.3 Data Freeze

The data freeze for the generator and reinforcement input assumptions for this analysis was October 2024 for the 2027, 2029 and the Future Grid study year. As a result, there may be some recent developments within the electricity network that are not included. However, all reasonable steps were taken to ensure that any significant updates to the assumptions were considered in the study.

3.4 Transmission Network Outage Programme

The previous ECP-2.3 constraints analysis included a representative transmission outage schedule. The outages within this schedule represented a geographical spread of circuits across the system and were each configured for a one-month period. This allowed a representation of outage impact in each geographical area to be included within the studies.

This outage schedule, with 86 one-month outages spanning over 9 months was also used in the ECP-2.4 constraint forecast. One modification from the ECP-2.3 constraint forecast outage schedule was the addition of the new Pollagh station on the Kilpaddoge – Tralee 110 kV line. The transmission outage schedule used in this analysis is given in Appendix A Table A-4. This outage schedule was formulated by working alongside the outage planning team within EirGrid and SONI.

This methodology was used as in reality a transmission outage programme will be implemented each year, resulting in outages of transmission circuits and other equipment for periods of time. Transmission outages may be due to scheduled maintenance, forced outages, to facilitate new connections or for reinforcement reasons (e.g., circuit/busbar uprates).

3.5 Battery Modelling

For this analysis batteries have been modelled using the battery class within PLEXOS. They have been modelled using the general assumptions shown in Table 3-1.

General Battery Modelling Assumptions	
Max. State of Charge	95%
Min. State of Charge	5%
Charge Efficiency	90%
Discharge Efficiency	90%
Max Cycles per Day	2

Table 3-1 General Battery Modelling Assumptions

The battery capacity (MWh) and max power (MW) have also been entered into the model and are specific to each battery.

For this analysis, the shorter duration batteries (batteries with a storage duration of <= 1 hours), were modelled to primarily supply reserve in the form of Primary Operating Reserve (POR), Secondary Operating Reserve (SOR), Tertiary Operating Reserve 1 (TOR1) & Tertiary Operating Reserve 2 (TOR2). However, the shorter duration batteries are also able to contribute to energy arbitrage when the reserve requirements were met. The reserve requirements used in the analysis is given in Section 3.11.2.4 (Table 3-9).

The longer duration batteries (batteries with a storage duration of > 1 hours) were modelled primarily to provide energy arbitrage. The cycling of these batteries was decided by the PLEXOS optimisation to maximise returns. The longer duration batteries were also able to supply replacement reserve. The replacement reserve requirements can be seen in Table 3-9.

This approach means that the longer duration batteries charge during times of high renewable generation when the system price is lower, therefore, integrating more solar and wind generation on the system.

For conventional generation, the dispatch is primarily economic in nature. As such, the software only runs the relatively expensive conventional generators infrequently in the simulation. Hence, the model generally does not dispatch batteries and peaking generators at times of high solar and wind generation output. However, with at lower RES the batteries can generate when their cost of generation is less than he conventional generators and are beneficial to batteries.

3.6 Priority Dispatch for Renewable Generation Connecting after July 2019

EU regulation 2019/943 published in June 2019 introduced a clause in relation to the treatment of priority dispatch for renewable generation which connected after the 4th of July 2019.

The relevant clause (Article 12) is as follows:

> *REGULATION (EU) 2019/943 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 5 June 2019 on the internal market for electricity*[10]
>
> *Article 12 (6)*
>
> *Without prejudice to contracts concluded before 4 July 2019, power-generating facilities that use renewable energy sources or high-efficiency cogeneration and were commissioned before 4 July 2019 and, when commissioned, were subject to priority dispatch under Article 15(5) of Directive 2012/27/EU or Article 16(2) of Directive 2009/28/EC of the European Parliament and of the Council*

[10] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0943&from=EN

(20) shall continue to benefit from priority dispatch. Priority dispatch shall no longer apply to such power-generating facilities from the date on which the power-generating facility becomes subject to significant modifications, which shall be deemed to be the case at least where a new connection agreement is required or where the generation capacity of the power-generating facility is increased.

Under Article 12, renewable generation that connected before 4th July 2019 will still hold priority dispatch status, while generation connected after this date will not. The application of constraints in relation to a renewable generator's priority status is often termed as the 'grandfathering' of constraints. The implementation of Article 12 will create a new type of generator for consideration in the dispatch process – the non-priority dispatch renewable generator, connected post 4th July 2019.

The SEMC published a decision paper in relation to Article 12, concerning dispatch, and Article 13, concerning redispatch, of the EU 2019/943 on the 22nd of March 2022[11] (SEM-22-009 Decision Paper on Dispatch, Redispatch and Compensation Pursuant to Regulation EU 2019/943)[12]. Following the Judicial decision on the SEM-22-009 Decision Paper, the detailed design of the implementation of Articles 12 and 13 has yet to be determined and may differ from implementation for constraints used in this study. Therefore, an assumed interpretation has been included in this study based on the 'enduring solution' explained in SEM-22-009, this interpretation has been outlined below. The enduring solution has been used as the base case interpretation of Article 12 and 13 for ECP-2.4 as it is due to be implemented in 2026 according to SEM-22-009.

During generation reduction for surplus reasons, a distinction is made between the treatment of priority and non-priority renewable generators, with non-priority generators being dispatched down ahead of priority generators. Within these two categories of generation, dispatch down to resolve the surplus is applied pro-rata across the all-island system for all generators in the category. Resolving surplus following this approach is consistent with ECP-2.3 methodology.

Similarly, methodology for curtailment of renewable generation from ECP-2.3 is unchanged, whereby no distinction is made between priority and non-priority generators, and dispatch down is applied pro-rata across the all-island system.

For constraint however, ECP-2.4 methodology has been updated to follow an interpretation of the enduring solution to Article 12 and 13. Under the updated methodology a distinction is made between the treatment of priority and non-priority renewable generators, with non-priority generators being dispatched down ahead of priority generators across the relevant transmission nodes contributing to the constraint. However, in addition to the Core ECP 2.4 constraint forecast studies a set of sensitivity studies are also included in the study scenarios which employs pro-rata allocation of constraints.

[11] https://www.semcommittee.com/publications/sem-22-009-decision-paper-dispatch-redispatch-and-compensation-pursuant-regulation-eu

[12] SEM-22-009 has been successfully challenged in the High Court ([2023] IEHC 629)

3.7 Network

3.7.1 Transmission Network

This section details the modelling assumptions used in this study for the transmission network.

The transmission system in Ireland and Northern Ireland is a meshed network with voltage levels at 400 kV, 275 kV, 220 kV and 110 kV. The network is necessary to allow bulk power flows to be transported over long distances from power stations and renewable generation sites to the towns and cities in Ireland and Northern Ireland. A diagram of the Irish transmission system in 2021 can be seen in Figure 3-1. In addition to the current transmission network a number of network reinforcements are considered in each network scenario (see Figure 3-2). A list of the network reinforcements used in the study is provided in Appendix A.

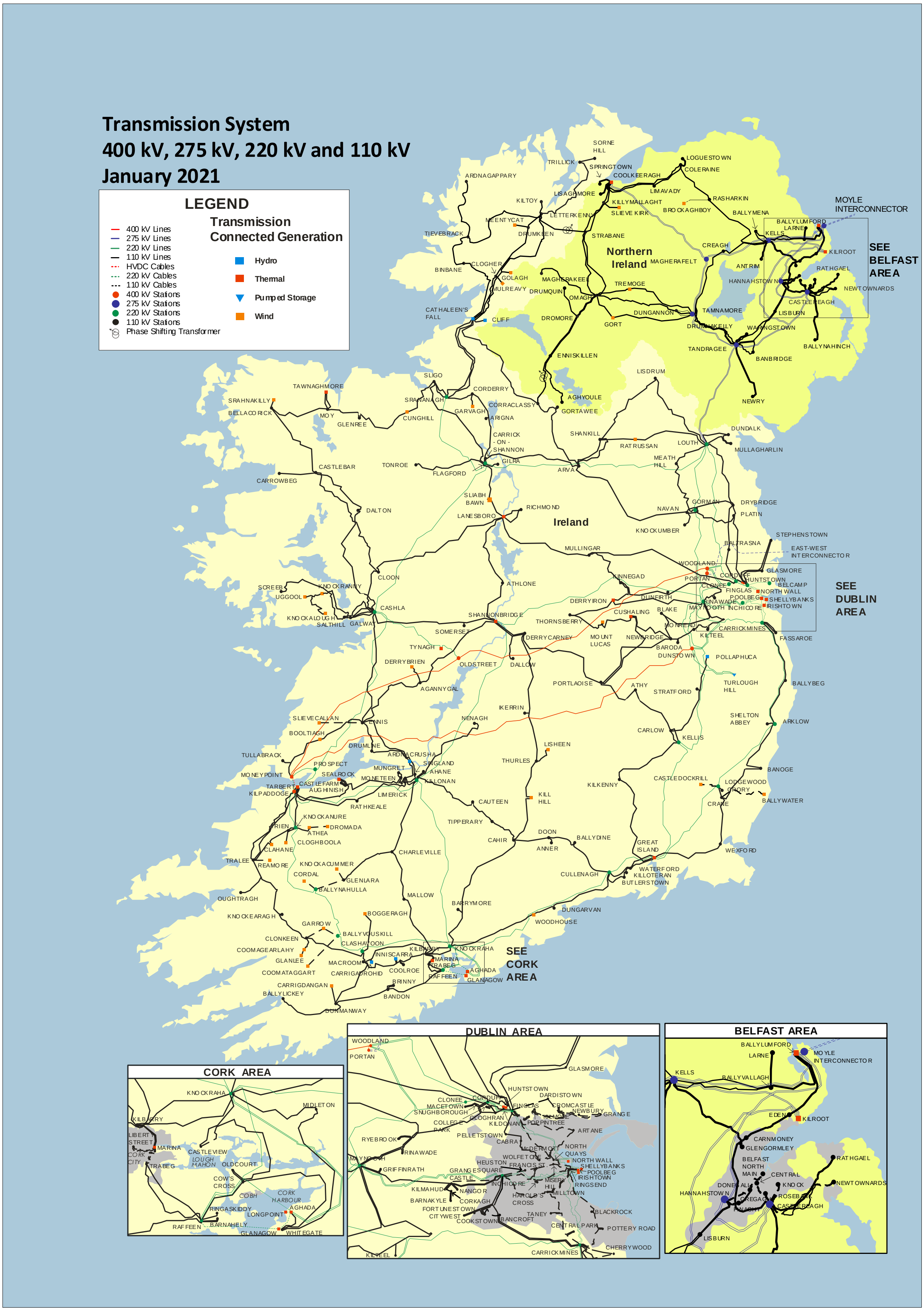

Figure 3-1 Ireland Transmission Network 2021

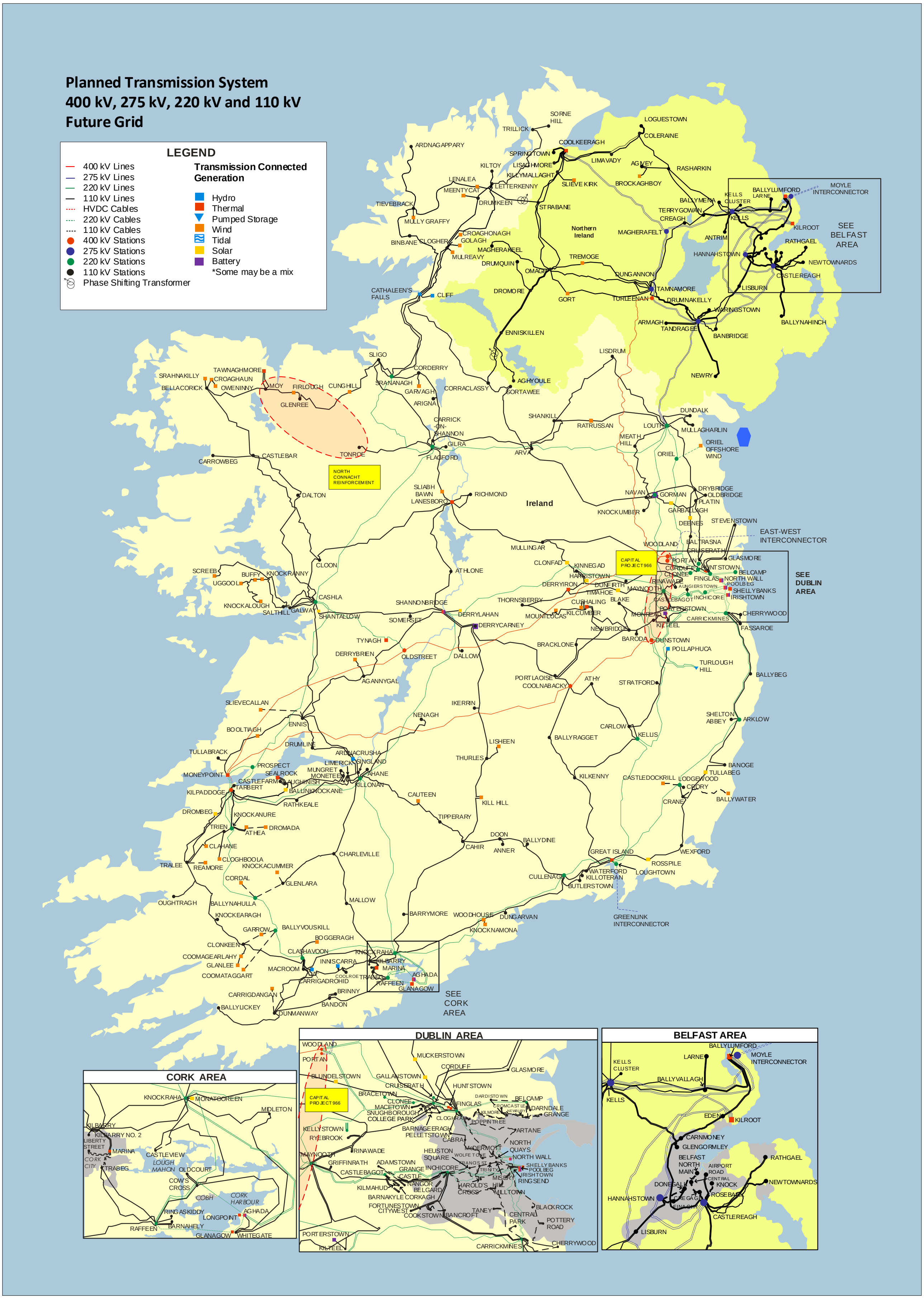

Figure 3-2 Ireland Transmission Network Showing Assumed Future Network Reinforcements and Stations

3.7.2 Distribution System

For the purposes of the constraints modelling, a simplified representation of the distribution system is used whereby all load and generation is assumed to be aggregated to the nearest transmission node. Hence, this report does not account for the impact of constraints (if any) on the distribution network.

3.7.3 Ratings and Overload Ratings

The Ireland transmission system is operated to safely accommodate a single transmission asset loss (N-1 contingency), this is to reflect the TSSPS (Transmission System Security & Planning Standards). While formulating an optimum dispatch, system operation takes account of potential overloads that could be caused as a result of certain N-1 contingencies on the transmission system. When determining if the post-contingency flows are within limits, the system operator uses the overload rating of the apparatus or plant (for N-1) as well as the normal rating (for N flows). Where available, the overload rating is typically higher than the normal rating but is only allowed in emergency conditions and for short periods of time. The overload rating is project specific. The PLEXOS models used for the ECP-2.4 constraints analysis include N-1 contingency monitoring and both ratings and overload ratings.

3.7.4 Transmission Reinforcements

For each study year (2027, 2029 and Future Grid) a number of transmission reinforcements are added to the model. These additional transmission reinforcements include overhead lines (OHL), and cable uprates as well as new build OHLs, cables and transformers.

Dynamic Line Rating (DLR) has also been applied to certain transmission lines throughout the network. DLR is an operational tool aimed at maximising electric power transmission when environmental conditions allow it. Within the PLEXOS model the DLR's are modelled with respect to wind availability within an area and can provide an increase in line rating.

A full list of the transmission reinforcements (new build, uprates and DLR's) assumed in the constraints modelling is included in Appendix A Table A-1 - Table A-3.

Customers should recognise that the reinforcements listed will be subject to a full analysis and optimisation process under EirGrid's Framework for Grid Development before a decision is made to proceed with them. Inclusion of transmission reinforcement projects in this report is not confirmation that they will proceed, and other projects may be selected in their place. For the avoidance of doubt, any party making a decision based on this list should recognise that these are modelling assumptions only and should not be considered as a basis in fact. Additional information about reinforcements is available on the EirGrid website[13].

3.8 Demand

An introduction to the demand used in this report is provided in Section 2.

The demand profile shapes for Ireland and Northern Ireland are based on their 2022 historical demand profiles. The historical profiles are adjusted to reflect a future winter peak (Transmission Winter Peak) and Total Energy Requirement (TER) based on the All-Island Resource Adequacy Assessment 2025 – 2034 median demand for the 2027, 2029 and 2030 (Future Grid) years. The values used are shown in Table 3-2.

[13] https://www.eirgridgroup.com/the-grid/projects/

	TER (TWh)			Transmission Peak (GW)		
Year	Ireland	Northern Ireland	All-Island	Ireland	Northern Ireland	All-Island
2027	41.1	9.05	50.2	6.35	1.71	8.04
2029	43.5	9.58	53.1	6.53	1.80	8.30
Future Grid	44.7	9.83	54.5	6.61	1.84	8.39

Table 3-2 Forecast Demand (TER) and Peak for Study Years 2027, 2029 and Future Grid

The nodal distribution of the load used in the constraints modelling is consistent with the "All-Island Ten-Year Transmission Forecast Statement 2022[14].

3.9 Interconnection

Existing interconnection on the island consists of a tie line between Ireland and Northern Ireland plus three High Voltage Direct Current (HVDC) interconnectors to Great Britain (GB), referred to as the Moyle Interconnector, the East-West Interconnector (EWIC), and the Greenlink Interconnector. This section describes the assumptions and modelling methodology used for interconnection in these studies.

3.9.1 North-South Tie Line

The connection of Ireland's power system to Northern Ireland is achieved via a double circuit 275 kV line running from Louth to Tandragee. In addition to the main 275 kV double circuit, there are two 110 kV connections: one between Letterkenny in Co. Donegal and Strabane in Co. Tyrone, and the other between Corraclassy in Co. Cavan and Enniskillen in Co. Fermanagh.

The purpose of these 110 kV circuits is to provide support to either transmission system for certain conditions or in the event of an unexpected circuit outage. Phase shifting transformers in Strabane and Enniskillen are used to control the power flow under normal conditions.

It is assumed that the Letterkenny - Strabane and Corraclassy - Enniskillen 110 kV connections are not used to transfer power between the two control areas for the purposes of this modelling exercise.

EirGrid and SONI are also currently developing a 400 kV North-South Interconnector between Woodland in Ireland and Turleenan in Northern Ireland. The new North-South Interconnector is assumed to be in place for the 2029 and Future Grid study years, this will result in a inter area flow of 1,000 MW. Although this assumption has become outdated due to recent changes, these updates have materialised after the data freeze date of October 2024.

3.9.2 Moyle Interconnector

The Moyle Interconnector, which began commercial operation in 2002, connects the electricity grids of Northern Ireland and Great Britain between Ballycronan More (Islandmagee) and Auchencrosh (Ayrshire). It has a transfer capacity of 500 MW, however, due to constraints on the transmission networks at either end this capacity can be reduced.

For the purposes of this study the Moyle Interconnector is assumed to have a 400 MW export capacity and a 450 MW import capacity for the 2027 study year. An assumption has been made that this will increase to 500 MW (export/import) for the 2029 study year and Future Grid study horizon.

[14] https://cms.eirgrid.ie/sites/default/files/publications/All%20Island%20Ten%20Year%20Transmission%20Statement-2022.pdf

3.9.3 East-West Interconnector (EWIC)

The East-West Interconnector links the electricity grids of Ireland and Great Britain, from convertor stations at Portan in Ireland to Shotton in Wales. It began commercial operation in December 2012.

The EWIC Interconnector is modelled for all study years with a maximum capacity of 500 MW.

3.9.4 Greenlink Interconnector

The Greenlink Interconnector, commissioned in 2024, connects the electricity grids of Ireland and Wales between Great Island (Co. Wexford) and Pembroke (Co. Pembrokeshire). The Greenlink Interconnector is connected for all study years with an import/export capacity of 500 MW.

3.9.5 Celtic Interconnector

The Celtic interconnector connecting Ireland with France is modelled in the 2029 and the Future Grid study year. In 2029, this subsea HVDC (High Voltage Direct Current) cable will have an import capacity of 560 MW and an export capacity of 700 MW. In the Future Grid study horizon, it has been modelled to have an import/ capacity of 700 MW.

3.9.6 LirIC Interconnector

The LirIC interconnector project is due to be commissioned in 2029 and will connect the electricity grids of Northern Ireland and Scotland. LirIC is assumed to be connected for the Future Grid study year.

3.9.7 The 2nd Ireland – France Interconnector

The 2nd Ireland – France interconnector has been assumed in the Future Grid horizon to reflect the network assumptions in the recently published SOEF 1.1 Roadmap.

3.9.8 Interconnector Capacities

The interconnector capacities used in the model are shown in Table 3-3.

Interconnector Name	Export/Import	2027 Model Capacity (MW)	2029 Model Capacity (MW)	Future Grid Model Capacity (MW)	Nameplate Capacity (MW)
Moyle	Export	400	500	500	500
	Import	450	500	500	500
EWIC	Export	500	500	500	500
	Import	500	500	500	500
Celtic	Export	-	700	700	700
	Import	-	700	700	700
Greenlink	Export	500	500	500	500
	Import	500	500	500	500
LirIC	Export	-	-	700	700
	Import	-	-	700	700
2nd Ireland - France	Export	-	-	700	700
	Import	-	-	700	700

Table 3-3 Interconnector Capacities

It is assumed that interconnectors can be used to export renewable energy, with the provision that, when calculating an annual average behaviour, it would be optimistic to assume that maximum interconnector export will always be available when required.

Recently, the interconnector flows have been more volatile and sufficient data or modelling methodology is not yet available to include in the ECP 2.4 constraint forecast and thus the methodology used in the ECP 2.3 constraints forecast will be continued. This may be updated in the next iteration of constraint analysis if a revised modelling methodology is available.

With respect to the ECP 2.3 modelling which is used in ECP 2.4 constraint forecast modelling, the Interconnectors model was created based on historical flow analysis for the GB region for the year 2020,2021 and 2021. The interconnectors to GB are modelled to have a full export capacity for 63% of the time. As a result, the Moyle, EWIC, Greenlink and LirIC interconnectors are modelled with an ability to export at full capacity for 63% of the time. While for 14% of the time the IC's to GB are considered to be available at 75% of their full capacity, and for 11% of the time they are available at 50% capacity, and 5% of the time with 25% of full capacity and the remainder with 0% export capacity. Using this information, the capacity of these IC's was assigned for the year.

Additional interconnector analysis was undertaken using a modified Ten-Year Network Development Plan (TYNDP) model. This analysis suggested that during times of high wind (wind output > 3 GW) there would be considerable exports from Ireland to France through the Celtic interconnector.

As there is currently no interconnector flow data between Ireland and France, we assumed an export capacity of 560 MW (de-rated by 20%) for the Celtic and 2nd Ireland – France interconnectors. For Celtic, this 20% de-rating for export will only be applied in the 2029 and Future Grid study. This has been assumed as there will be times when the market schedule will provide less export than theoretically possible. An example of this may include, when the receiving country may not be in a position to accept large trades. The use of full interconnection capacity may lead to the understating of dispatch down levels.

Further, this modelling approach assumes that the flow on interconnector area aligned with market dynamics where power flows from low price region to high price region.

3.10 Generation

An introduction and overview of the generation in this study is provided in Section 2. Additional detail is now provided in this section.

3.10.1 Conventional Generation

The model includes a portfolio of the thermal conventional generation in both Ireland and Northern Ireland. The operating characteristics of the existing conventional generation employed in the model are principally based on the SEM Generator Dataset. In some instances, minor changes to the dataset are made due to additional information becoming available to the TSOs.

The technical dataset includes the following information:

1. Fuel type (e.g., gas, coal etc.) including emissions rates.
2. Maximum and minimum operating output (MW).
3. Capacity state and heat rates (used to determine how much fuel is burnt to produce 1 MW of output power).
4. Ramp rates (important to determine how quickly a machine can change its power output).
5. Minimum up-time and downtime.

This technical data allows the PLEXOS software to calculate the cost of generating a megawatt of electrical energy for each generator in the model. Note that each generator has a different cost.

Other factors that influence the generation dispatch over an extended study horizon are:

- Generation commissioning and decommissioning.
- Generation outages.
- Generation emission restrictions.

3.10.2 Conventional Generation Outages

Scheduled and forced conventional generator outages are modelled in PLEXOS using Scheduled Outage Durations (SODs) and Forced Outage Probabilities (FOPs).

For this study, the Forced Outage Probabilities are used. The FOPs employed are those used for the Dispatch Balancing Costs (DBC) 2021 – 2022 Forecast. PLEXOS generates forced outage patterns from the FOPs and mean time to repair data. This provides a deterministic outage pattern against which the model dispatches generation against demand.

3.10.3 Renewable Generation

The amount of electrical energy output from renewable generation is generally described in terms of capacity factor. The capacity factor relates to the amount of energy that may be achieved from a renewable technology over the period of one calendar year. Generally solar PV has a lower capacity factor than wind generation. One factor in the energy yield difference is that solar PV does not produce electrical energy at night, but the wind can blow at any time of the day or night.

The capacity factor values used in this study for solar and wind generation are listed in the following sections.

3.10.3.1 Solar

On average, solar profiles tend to have a fairly predictable shape. Figure 3-3 shows the average hourly energy output from a solar PV site over a one-year period. The capacity factor for solar PV is largely dependent on latitude – the closer to the equator the higher the annual capacity factor. The solar capacity factor for a country like Spain will have a value of around 20%, i.e., approximately double the output of Ireland.

The surface plot of Figure 3-3 highlights the typical Ireland solar profile characteristic. The lowest intensity of solar electrical output is in the four winter months November through to February with hourly values on average not exceeding 20% of the PV panels max output. As expected, the solar electrical energy output is highest in the summer months with average hourly solar electrical output peaking in the 50%-60% range.

A key point to note is that the solar electrical available energy is fairly predictable and is typically there during times of increasing electrical demand such as the morning load demand rise. However, the winter peak demand will not be met by solar.

Furthermore, solar energy output may be reduced if it is located on a part of the network that has constraint issues.

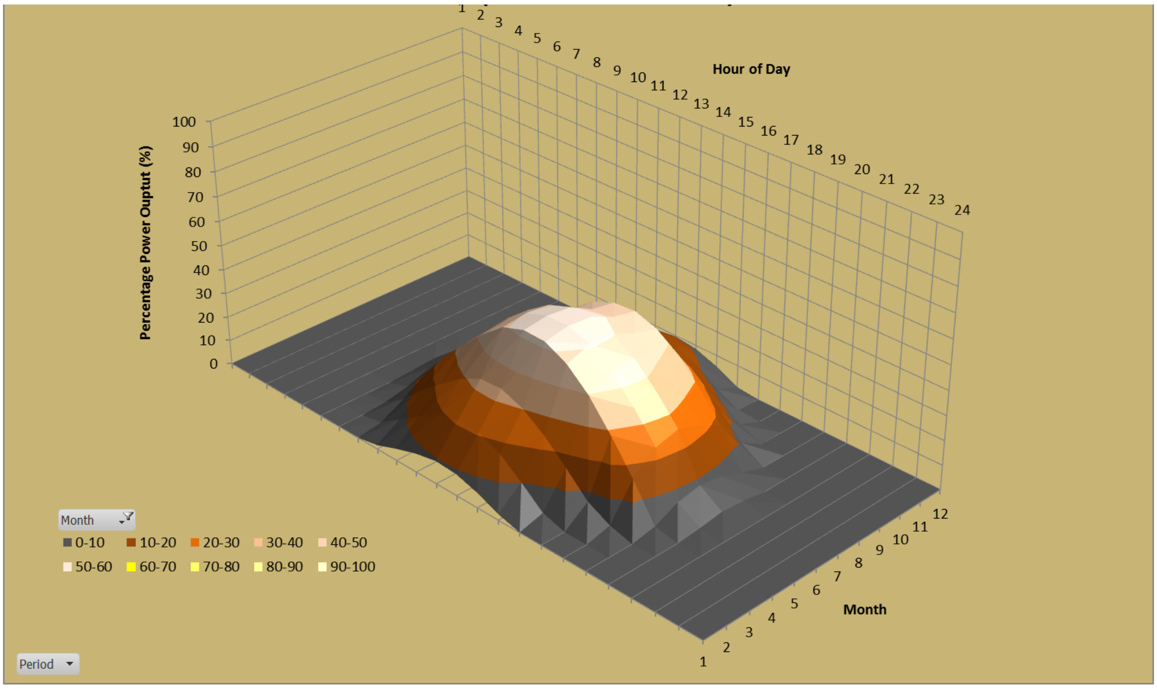

Figure 3-3 Representative Solar Energy Profile (Monthly Average – Hour of Day)

3.10.3.2 Solar Profiles

Solar generation is modelled in the analysis using an hourly solar power series at every transmission node where solar generation is connected.

For the previous ECP-2.3 analysis, three solar profiles were used: solar north, solar middle, and solar south. The solar north profile was obtained from data recorded from a solar plant in Northern Ireland for the year 2020. The solar middle and solar south profiles were obtained by EirGrid through industry engagement.

In the latest ECP-2.4 analysis the same grouping approach is used, however, the solar profiles have been updated. New solar data has been obtained from an external vendor and has been synthesised from 2020 data.

This solar grouping approach captures the variations in solar energy when comparing solar farms in the north to solar farms in the south. This approach does not consider hourly variations in solar power within each area, due to local cloud cover in that individual hour. Since this study is focused on the surplus, curtailment, and constraint on the transmission system, it is reasonable to assume that these solar profiles capture the average behaviour of solar on the island.

The groupings used and the capacity factors of the different profiles are shown in Figure 3-4 and Table 3-4.

Figure 3-4 Capacity Factors of Groupings Used for Solar Profiles in the Model

Solar	Capacity Factor
Solar North	12.0%
Solar Middle	14.6%
Solar South	13.3%

Table 3-4 Capacity Factor of Solar Profiles

3.10.3.3 Wind

This section details how wind generation on the island of Ireland is modelled within PLEXOS.

Wind generation is modelled using an hourly wind power series at every transmission node where wind generation is connected.

To provide a representative wind series, wind profiles are used. In this study, wind profiles are used for all wind farms in an area, i.e., the same wind profile is used for all wind generators in a single area.

By using historical wind profiles, it is possible to account for the geographical variation of wind power across the island. For the ECP-2.4 constraints analysis 2020 wind data is used for the onshore wind profiles, this is consistent with ECP-2.3. The offshore wind profiles have been procured from an external vendor; these profiles have been synthesised from 2020 data.

The capacity factors of these wind profiles are shown in Figure 3-5 and in Table 3-5.

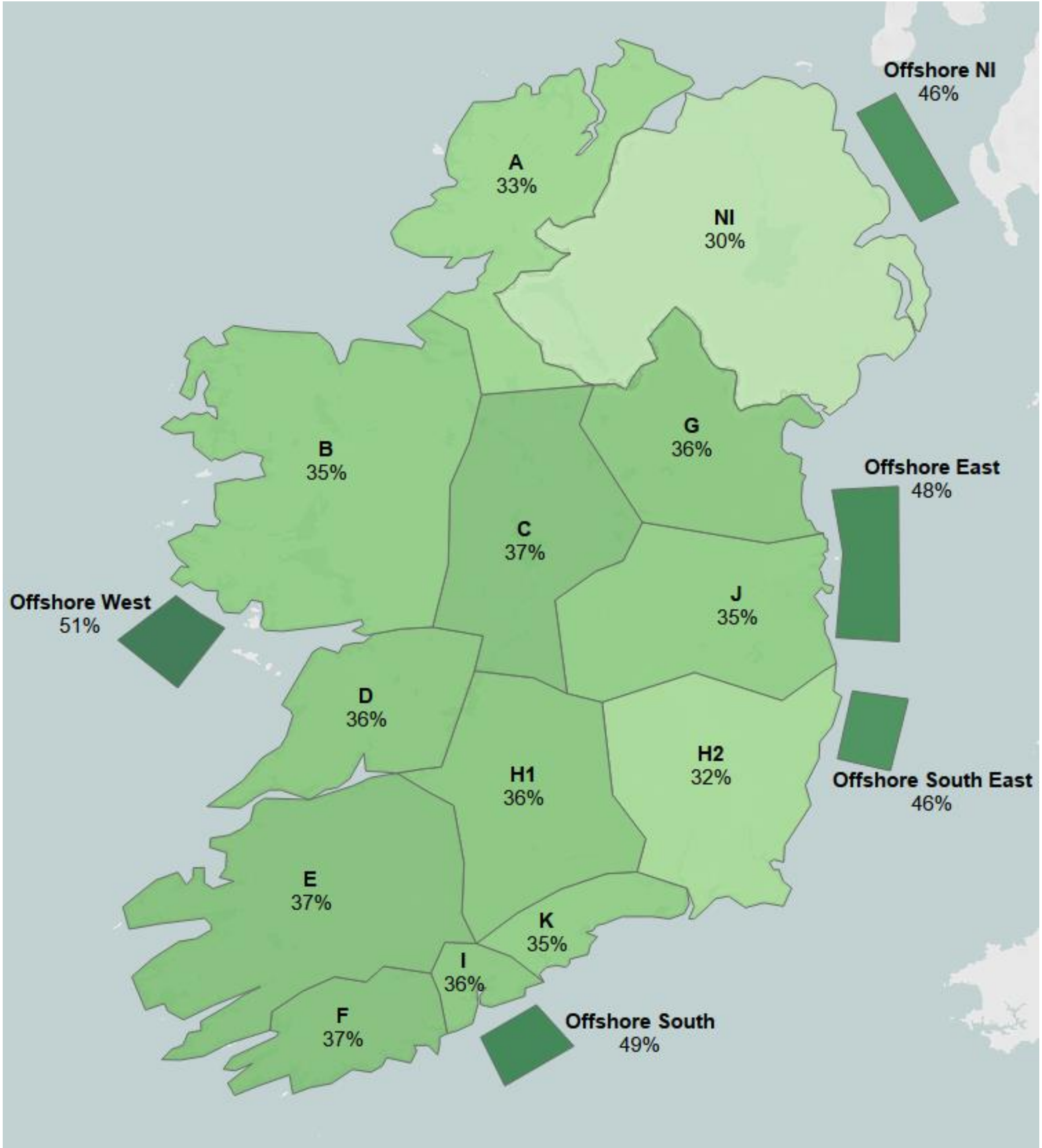

Figure 3-5 2020 Capacity Factor by Area for Wind

Wind Regions	2020 Capacity Factors
Ireland	
A	33%
B	35%
C	37%
D	36%
E	37%
F	37%
G	36%
H1	36%
H2	32%
I	36%
J	35%
K	35%
Offshore West	51%
Offshore East	48%
Offshore South East	46%
Offshore South	49%
Northern Ireland	
NI	30%
Offshore NI	46%

Table 3-5 Capacity Factors for Future Wind

Similar to 2015 wind data, 2020 wind data has a comparatively high-capacity factor (high wind year). This value is representative of a wind fleet that will include new onshore and offshore wind farms incorporating the latest available technology.

3.10.3.4 Installed Capacity

Section 2 describes the renewable generation scenarios that are considered as part of this analysis. Some further detail is provided here.

A variety of renewable generation scenarios are included to take account of the possibility that not all generators will ultimately connect, and to give a view on the Total Dispatch Down seen under various renewable generation build out rates. The levels of installed battery, solar, wind and wind offshore generation included in each scenario are shown in Table 3-6.

The Initial scenario includes currently connected renewable generation plus all renewable generation expected to be connected by the end of the year prior to the study year, i.e., 2026 for the Initial 2027 Scenario. The “ECP” scenario includes all renewable generation up to and including ECP-2.4 for the given study year. The 50% scenario was created by scaling the outputs of generators assumed to connect within the study year by 50%.

ECP-2.4 Breakdown of IE Generation Capacity (MW)						
	Initial Study	50% Study	ECP All Study	ECP without batteries	ECP +3.1 GW offshore	ECP + 5 GW offshore
Battery	896	2,218	3,539	766	3,539	3,539
Solar	1,539	4,272	7,005	7,005	7,005	7,005
Wind	5,212	6,272	7,333	7,333	7,333	7,333
Wind Offshore	25	25	25	25	3,099	5,025
Totals	**7,672**	**12,787**	**17,902**	**15,129**	**20,976**	**22,902**

Table 3-6 Connected and Contracted Battery, Solar, Wind and Wind Offshore Quantities in Ireland for the Study Scenarios

3.10.3.5 Generation Controllability

Historically smaller (and some older) wind farms and solar generators are not controllable. The study methodology takes into account all uncontrollable wind and solar generation and does not include these generators in any output reduction calculations.

Generally, apart from some older windfarms, it is assumed that all wind farms are controllable if their maximum export capacity (MEC) is greater than or equal to 5 MW (for generators which received a connection offer before 2015) or if their MEC is greater than or equal to 1 MW (after 2015). All solar farms with an MEC greater than or equal to 1 MW are assumed to be controllable.

3.10.3.6 Perfect Foresight - Wind Forecast

Building an economic power market model will always require input assumptions. One such assumption is that the climatic year will be from historical data. The use of historical data means that the power market model will create generation commitment and dispatch decisions based on the perfect foresight of wind and solar output. In real-time operation of the power system, this is not the case and there will be forecast errors associated with variable renewables and demand. Perfect foresight may mean that power market models show lower levels of curtailment since it may choose to de-commit units based on what it knows will happen. In reality, wind or demand forecast errors may mean that a different schedule of generators may be required than that modelled with perfect foresight.

3.11 System Operation

3.11.1 Safe Operation (Security Constrained N-1)

The basic principle of N-1 security in network planning states that if a component, such as a transformer or circuit, should fail in a network, then the network security must still be guaranteed, and the remaining network resources must not be overloaded or exceed the short-term overload capability of the equipment. System voltage must also remain within permitted limits; however, it should be noted that PLEXOS is a DC load flow analysis tool and does not monitor system voltage as part of this study.

EirGrid plans and operates the Ireland transmission network to be N-1 secure. This PLEXOS study also monitors N-1 contingencies to ensure the results are valid for an N-1 secure network.

3.11.2 Operational Constraint Rules

This section presents the all-island operational constraints, which feed into the PLEXOS economic dispatch tool. The operational constraints cover System Non-Synchronous Penetration (SNSP), inertia, operating reserve requirements and minimum number of synchronous units required.

The purpose of this section is to define the set of operational constraints, and how these constraints may evolve over the proposed study horizons. Operational constraints are important as they define system limits that may require reductions in renewable generation, resulting in curtailment. In general, it is expected that certain operational constraints may be relaxed over time, as the system evolves.

3.11.2.1 System-Wide Operational Constraints

There are several system-wide operational constraints which ensure that the system operators can operate the system securely and within stability limits. This study uses the operational constraints listed in Table 3-7. These operational constraints have been taken from the Operational Policy Roadmap 2023 – 2030[15], the TSO Imperfections and Constraints Multi-year Plan 2024 – 2028[16], and are aligned to the SOEF 1.1 Roadmap where applicable. The RoCoF limit was not monitored in the PLEXOS study but is included in Table 3-7 for information purposes.

[15] https://www.eirgridgroup.com/site-files/library/EirGrid/Operational-Policy-Roadmap-2023-to-2030.pdf
[16] https://consult.eirgrid.ie/en/system/files/consultation-outcomes-reports/Imperfections%20and%20Constraints%20Multi-Year-Plan%202024_2028%20FINAL.pdf

Active System Wide Constraints		ECP-2.4 Assumptions
System Non-Synchronous Penetration (SNSP)	There is a requirement to limit the instantaneous penetration of asynchronous generation connected to the All-Island system.	• 2027 - 85% • 2029 - 90% • Future Grid - 95%
Operational Limit for Rate of Change of Frequency (RoCoF)	There is a requirement to limit the RoCoF on the All-Island system.	• 2027 - 1 Hz/sec • 2029 - 1 Hz/sec • Future Grid - 1 Hz/sec
Operational Limit for Inertia	There is a requirement to have a minimum level of inertia on the All-Island system.	• 2027 - 23,000 MWs • 2029 - 23,000 MWs • Future Grid - 23,000 MWs
Minimum Sets **(IE, NI)**	There is a requirement to have a minimum number of conventional generators in Ireland and Northern Ireland.	• 2027 - 7 (4,3) • 2029 - 4 (2,2) • Future Grid - 3 (No jurisdictional split)
Reserve **(IE, NI)**	The amount of spare capacity in the system to manage any system disturbance.	• POR • SOR • TOR I • TOR II

Table 3-7 Active System Wide Operational Constraints (SNSP, Inertia & Minimum Sets)

3.11.2.2 System Non-Synchronous Penetration (SNSP)

There is a system need to limit the amount of 'non-synchronous' generation at any point in time. The limit ensures that the power system operates within a stable zone.

A mathematical expression describing the SNSP rule is as follows:

$$\frac{All\ Island\ Asynchronous\ Generation + Interconnector\ Imports}{All\ Island\ Demand + Interconnector\ Exports} \leq SNSP\ Limit$$

An increase in the SNSP limit will allow more 'non-synchronous' generation to be accepted onto the system.

3.11.2.3 Minimum Number of Synchronous Generators

There is a requirement to have a minimum number of conventional generators synchronised at all times to provide inertia to the power system, ensure voltage stability, dynamic stability and to ensure that network limitations (line loading and system voltages) are respected. The minimum number of units in each study horizon is given in Table 3-7.

Changes to the rules are guided by operational and/or planning assumptions. Table 3-8 provides the current requirements for minimum number of conventional units required on the system. Please note that the All-Island minimum set rule is currently being trialled using 7 units[17].

[17] https://www.sem-o.com/documents/general-publications/Wk04_2024_Weekly_Operational_Constraints_Update.pdf

Minimum Conventional Generation Assumptions
Ireland
A minimum of 2 large units in the Dublin region must be synchronised at all times. A minimum of 5 large units in Ireland must be synchronised at all times.
Northern Ireland
A minimum of 3 large units in Northern Ireland must be synchronised at all times.

Table 3-8 Summary of Current Conventional Minimum Generation Assumptions

3.11.2.4 Operating Reserve

Operating reserve is surplus operating capacity that can instantly respond to a sudden increase in load or decrease in generation output. Operating reserve provides a safety margin that helps ensure reliable electricity supply despite variability in the load and generation. To provide reserve, some generators are part-loaded i.e., are operated below their maximum output capacity to provide a fast-acting source of reserve. Reserve can also be provided by non-conventional sources such as batteries, storage, interconnectors, and demand response, in the future, it is expected that a greater share of reserve may be maintained by such non-conventional sources.

For the ECP-2.4 constraints analysis, batteries with a storage duration of less than and equal to 1-hour were modelled to provide primary, secondary, and tertiary operating reserve. Batteries with a storage duration greater than 1-hour were modelled to provide replacement reserve only. Due to a sufficient volume of batteries within the analysis with a storage capacity of less than and equal to 1-hour, all operating reserve required in the analysis was supplied by batteries – this is assumed to be the case in the modelling horizon of the ECP-2.4 constraints analysis. The operating reserve requirements modelled in the analysis can be seen in Table 3-9.

Operating Reserve Requirements			
Limit	**All-Island Requirement % of Largest In-Feed**	**Ireland Minimum (MW)**	**Northern Ireland Minimum (MW)**
Primary Operating Reserve (POR)	100%	155	50
Regulating Sources of Primary Operating Reserve (POR*)	-	75	50
Secondary Operating Reserve (SOR)	100%	155	50
Tertiary Operating Reserve 1 (TOR1)	100%	155	50
Tertiary Operating Reserve 2 (TOR2)	100%	155	50

Table 3-9 Operating Reserve Requirements for 2027, 2029, and Future Grid study scenario

4 Study Methodology

This section provides an overview of the modelling methodology employed to determine the likely surplus, curtailment and constraint levels for renewable generation in this study.

The methodology of production cost modelling is utilised to conduct the studies for this report. This section includes a description of production cost modelling, and an overview of PLEXOS (the modelling tool employed) is also provided. In addition, there is a description of the surplus, curtailment, and constraint modelling methodology.

4.1 Production Cost Modelling

In general terms, production cost models utilise optimisation algorithms with the objective of minimising the cost of generating power to meet demand in a region while satisfying operational, security and environmental constraints. A production cost model minimises the combined fuel cost, CO_2 cost, variable operation, maintenance, and start-up cost. In the model, wind and solar generation are variable sources with zero production cost. Hydro generation also has zero production cost but is energy limited. Chronological production cost models optimise generator commitment and dispatch scheduling for every hour of a study period (typically one-year duration).

Production cost models require:

- Specification of individual generator capabilities including capacity, start-up energy, annual forced outage rate, annual scheduled outage duration, reserve provision capabilities, emission rates and heat rates (fuel input requirement per unit output generation).
- Specification of the hourly demand profile for the region.
- Specification of the fuel price for each type of fuel.
- Specification of the transmission network (required for studies where transmission constraint information is the desired output).
- Specification of contingencies.
- System security constraints such as the requirement for reserve.
- Generator operational constraints such as maximum and minimum operational levels, ramp rates, minimum runtimes, and downtimes etc.
- Environmental considerations such as the cost of CO_2.

The commercially available production cost modelling tool employed in this study is PLEXOS.

4.2 The Software: PLEXOS Integrated Energy Model

PLEXOS is a detailed generation and transmission analysis program that has been widely used in the electricity industry for many years. EirGrid has extensive experience in using this simulation tool to model the Irish power system. It is a production cost modelling simulation program, used to determine power system performance and cost. It is a complex and powerful tool for power system analysis, with separate commitment and dispatch algorithms.

4.2.1 Commitment and Dispatch

The commitment process refers to the selection of a number of generators, from the total generation portfolio, that are available to meet customer demand. The decision as to when these generators should be on or off-line is also part of the commitment process. For example, additional generation is committed on Monday mornings to meet the higher weekday demand compared to the lower weekend demand where less generation is required.

The dispatch process refers to the decisions taken on the loading of individual generation units. Thus, the contribution from each online or committed unit towards meeting customer demand is determined by the dispatch decision.

4.2.2 Generation, Demand and Network

Full technical performance characteristics and operational cost details of each generation unit on the system are specified. An hourly system demand profile is also required. Additionally, in this constraints analysis study, the transmission system is modelled.

The program output provides complete details of the operation of each generation unit. These are aggregated into system totals. Flows on transmission lines can be monitored and potential constraints on the system can be identified. A wide range of output reports are available, from system summaries to hour-by-hour information on individual generators.

4.2.3 DC Load flow

PLEXOS is a DC load flow simulation tool. Therefore, it only models real power flows and does not consider voltage. Transmission plant and line ratings are MVA rated, and ratings vary with voltage. For the purposes of modelling the DC load flow MW ratings for the circuits, the model assumes a conversion factor of 0.9.

The conversion factor allows the necessary spare capacity for reactive power on the circuits, and it allows for post-contingency low voltage. This 0.9 conversion factor gives a good performance for a wide range of pre-contingency and post-contingency conditions.

The PLEXOS model, as constructed, does not account for losses. However, losses are accounted for within the Total Electricity Requirement (TER) demand figures.

4.3 System Model

For this study, the system is modelled at generator level where each conventional generator is modelled in detail. Characteristics such as heat rates, ramp rates, minimum runtime and downtime, start-up energy, reserve provision capabilities, annual forced outage rate, annual scheduled outage duration and emission rates of each individual generator are specified.

Solar and wind powered generators are modelled at 110 kV node level. In other words, if several windfarms are fed from a 110 kV node, the model represents them as a single windfarm at that node. The same is true for solar farms. These generators use hourly generation profile series. More detail on the modelling of solar and wind powered generation is provided in Section 3.10.3.

Ireland and Northern Ireland are treated as a single dispatch system in the production cost model for the purposes of producing an optimal minimum cost commitment and dispatch. Generators are dispatched based on their short-run marginal costs (which include the cost of fuel and CO_2 emissions) and in accordance with the dispatch assumptions outlined below.

4.4 Software Determination of Surplus, Curtailment and Constraint

For this report, wind and solar generators are assumed to be Grid Code compliant and it is assumed that controllable wind and solar generators can be instructed to reduce their output if required. It is worth noting that there are a small number of older wind turbine sites that are uncontrollable, as mentioned in Section 3.10.3.5.

The PLEXOS model is used to calculate surplus, curtailment, and constraint. A number of supplementary studies are also needed to properly apportion each of these three types of reduction in generator output.

In the simulation, generators are committed and dispatched in the most economical manner while satisfying operational and security constraints such as limitations on the instantaneous wind/solar penetration, operating reserve requirements, requirement for a minimum number of synchronised conventional generators, system inertia limits, as well as the limitations of the transmission network.

The simulation is a security constrained N-1 study. This means that the network flows are constantly monitored to be safe against the possible loss of any single item of transmission equipment.

The total reduction in energy for each renewable generator is calculated by comparing the renewable energy output from the simulation with the available renewable energy.

4.5 Apportioning of Surplus, Curtailment and Constraint

4.5.1 Surplus

As per Article 12 of the EU's Clean Energy Package, priority dispatch of renewable generation will continue to apply only to generators which connected prior to July 4th of 2019.

For this study, during generation reduction for surplus reasons, a distinction is made between the treatment of priority and non-priority renewable generators, and non-priority generators are dispatched down ahead of priority generators. Within these two categories of generation, surplus is applied pro-rata across the all-island system for all generators in this category.

4.5.2 Curtailment

For hours when it is necessary to curtail wind and solar generation output, a decision must be made as to which generators should have their output reduced. It is assumed in this study that, where possible, all controllable wind and solar generators share the reduction in output energy arising from curtailment in proportion to their available energy in that hour i.e., on a pro-rata basis.

4.5.3 Constraint

When a transmission constraint occurs, PLEXOS will attempt to alleviate the constraint in the most cost-effective manner.

If a transmission constraint causes wind or solar generation to be constrained down, PLEXOS' internal dispatch logic may choose one generator to constrain down out of several that have the same flow impact on the constraint (due to the fact that, in the constraints model, all wind and solar generators are modelled with zero cost of production).

This report studies the connection of very large amounts of generation to the transmission network. As such, there are some areas where the levels of transmission constraints are both large and frequent. There are also areas where there are, at times, several overlapping operational and transmission constraints. This makes it more difficult to apportion curtailment and constraints to individual nodes.

Post-processing of the results is required to ensure study results are more representative of the application of a constraint instruction. The process involves sharing the constraint volume proportionally between generators that have a similar impact on a constraint issue.

After several engagements with industry and the regulator for the purposes of this study grandfathering of constraints is employed for the base case. Grandfathering of constraints within a subgroup or area has been applied reflecting the enduring solution to constraint resolution; outlined in SEM decision paper SEM-22-009. This will result in non-priority wind and solar generation being constrained down before priority generators. The grandfathering of constraints will apply pro-rata to the non-priority units within a subgroup/area first, and then if the constraint is still not satisfied, the priority units within that subgroup/area will be constrained. However, in addition to the Core ECP 2.4 constraint forecast studies a set of sensitivity studies are also included in the study scenarios which employs pro-rata allocation of constraints.

5 Results Summary for Ireland

This section provides a summary of the Total Dispatch Down levels estimated by this analysis at a system level for Ireland.

Results are shown for the core study scenarios consisting of:

- Study year scenarios 2027 (pro-rata) and 2029 (grandfathering).
- Renewable generation scenarios Initial, 50%, and ECP.

Results are also shown for the sensitivity study scenarios that were developed in consultation with industry, and in response to industry feedback, consisting of:

- 2027 Study: 50% scenario (constraint allocation based on grandfathering).
- 2029 Study: 50% scenario (constraint allocation based on pro-rata), ECP scenario without batteries (constraint allocation based on grandfathering).
- A Future Grid study based on 2030 demand levels and aligned with the network from the SOEF 1.1 Roadmap.
- An ECP scenario (constraint allocation based on grandfathering) in the Future Grid.
- Four offshore wind scenarios in the Future Grid including:
  - ECP + 3.1 GW offshore (constraint allocation based on grandfathering).
  - ECP + 3.1 GW offshore (constraint allocation based on pro-rata).
  - ECP + 5 GW offshore (constraint allocation based on grandfathering).
  - ECP + 5 GW offshore with interconnector sensitivity, i.e., without LirIC and 2nd France interconnector (constraint allocation based on grandfathering).
- ECP battery study: A battery sensitivity study based on the 2029 ECP scenario, containing all renewable generation as in the ECP study scenario with non-connected batteries removed.
- A maintenance sensitivity study based on the 2027 ECP, 2029 ECP and Future Grid ECP + 3.1GW offshore scenario is included.

Figure 5-1, Figure 5-2 and Figure 5-3 provide an overview of:

- System Total Dispatch Down percentage levels; broken down by surplus, curtailment, and constraint.
- System Total Dispatch Down and wind and solar generated energy levels in TWh; broken down by surplus, curtailment, constraint, and generation.
- Total Dispatch Down percentage levels per area; broken down by solar non-priority, wind non-priority and wind priority.

In general, a reduction in Total Dispatch Down levels is seen in later study years due to the benefits of network reinforcements, future interconnection, relaxation of operational constraints and increased demand levels.

An increase in Total Dispatch Down levels is seen for the offshore sensitivity studies, which is largely driven by surplus.

More detailed results for each area can be seen in the corresponding area reports.

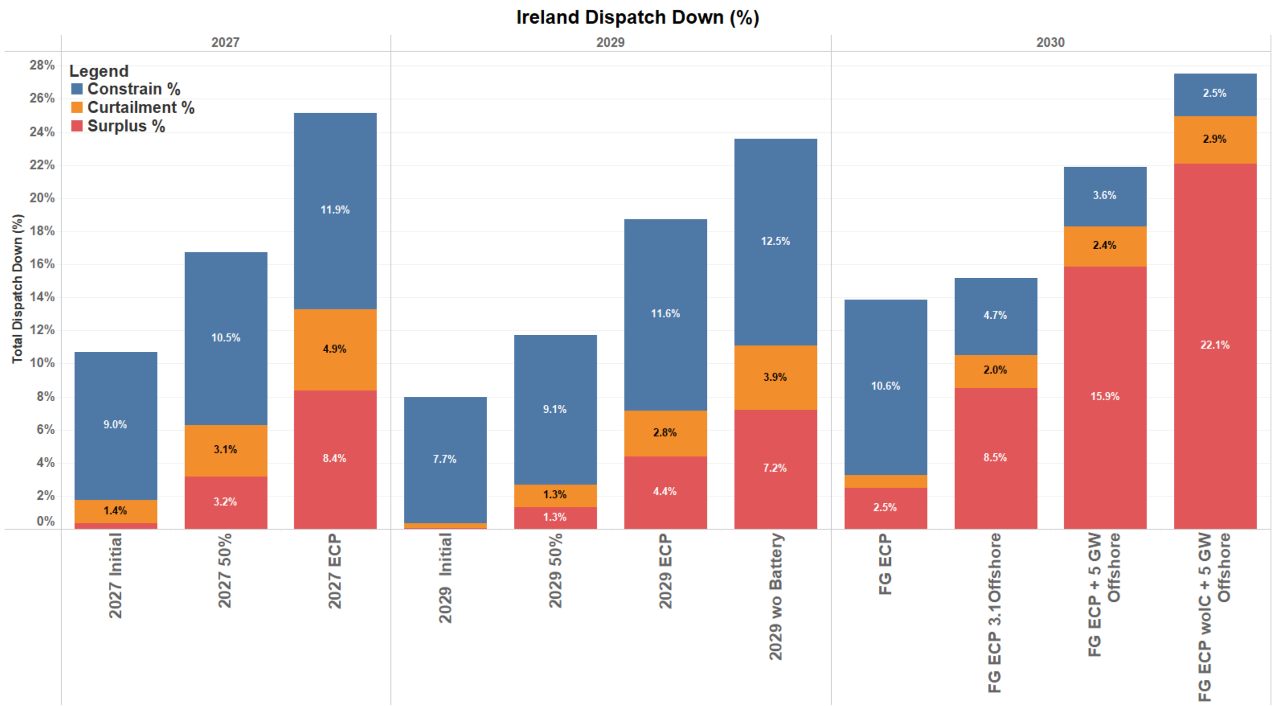

Figure 5-1 System Total Dispatch Down Percentage

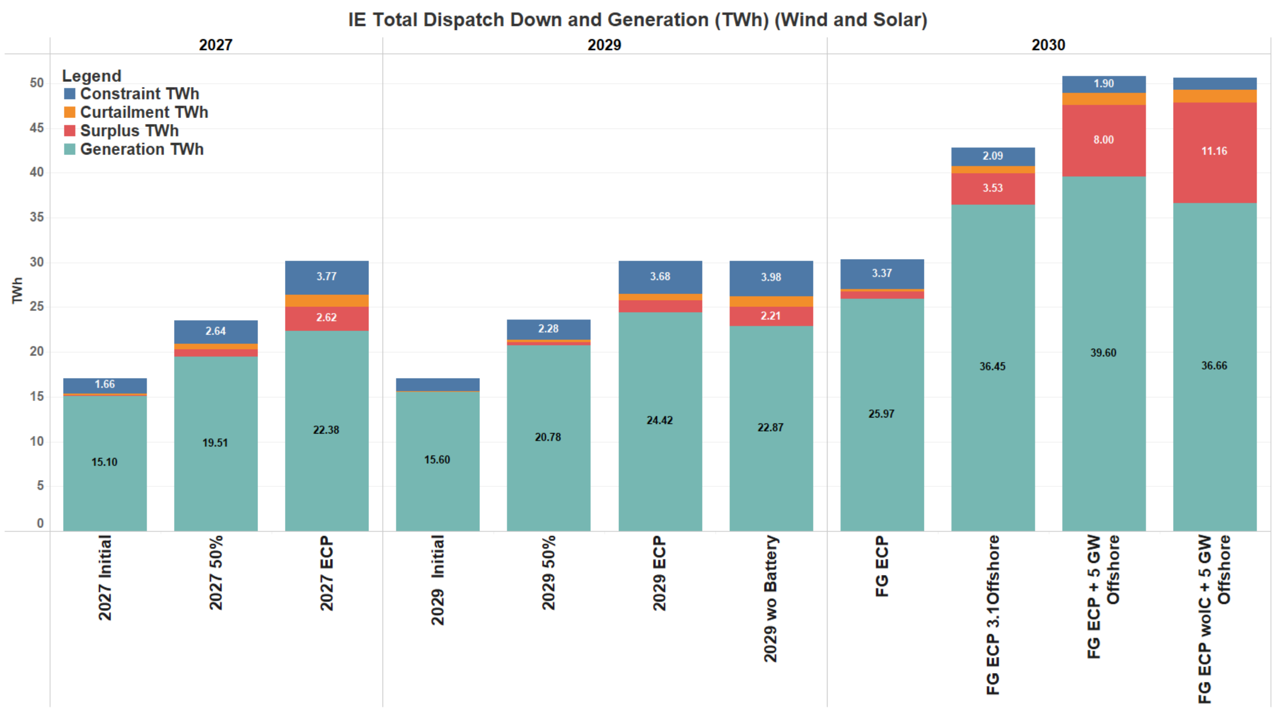

Figure 5-2 Total Dispatch Down and Generation for Wind and Solar in Ireland (TWh)

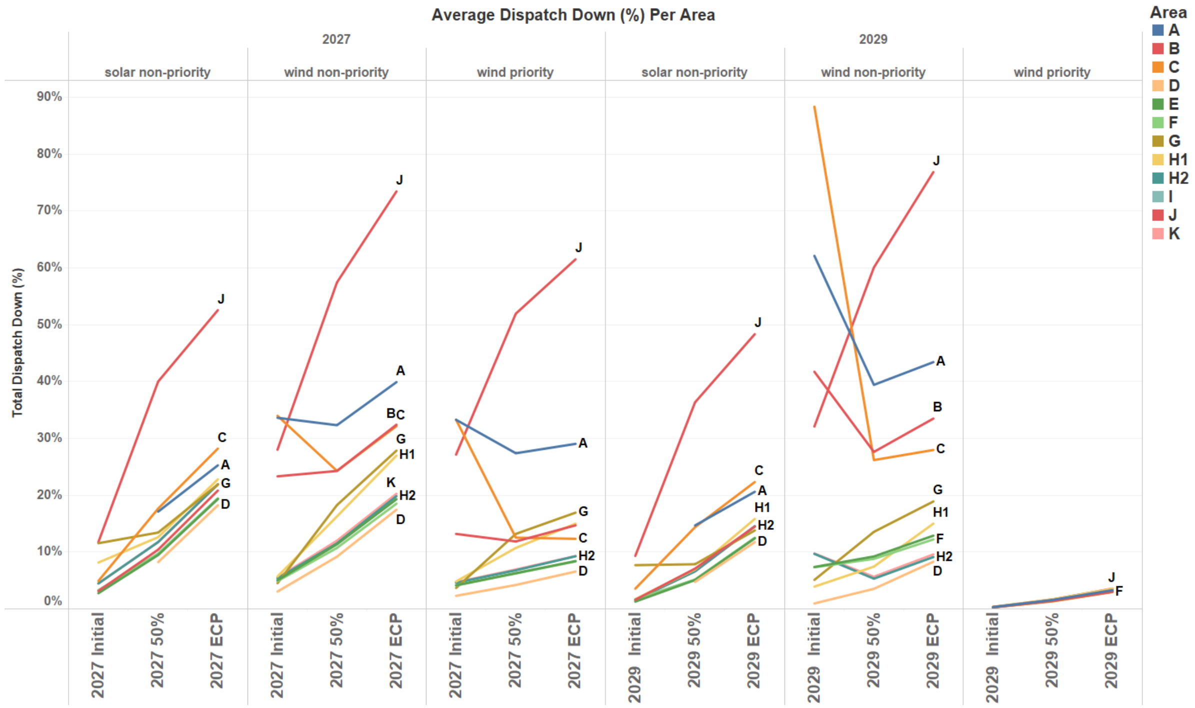

Figure 5-3 Total Dispatch Down Percentage per Area

5.1 Maintenance Sensitivity Study Report

Following ECP-1.0, industry feedback suggested that including a maintenance outage programme would be beneficial. Hence, as part of ECP-2.1 a representative maintenance programme was included in the baseline models and a further addendum was published which included a sensitivity to show the impact of this maintenance outage programme. In ECP-2.4 constraint forecast reports, a maintenance-based sensitivity has been included and published as part of the main report.

ECP-2.4 follows this same methodology (as in ECP-2.1, ECP-2.2, and ECP-2.3) with a representative maintenance programme (given in Table A-4). The maintenance program included is the same as the representative maintenance program used in the ECP-2.3 constraint forecast studies. The maintenance schedule was discussed with our internal operations team, and it provides a reasonable representative outage programme for the network. However, every maintenance and outage season is different, and the results need to be interpreted with this in mind.

This section provides results of a sensitivity study performed to quantify the impact of the maintenance schedule used in the ECP-2.4 constraints analysis. The study selected for the sensitivity is the 2027 ECP, 2029 ECP, Future Grid ECP and Future Grid ECP + 3.1 GW offshore scenario. All other study assumptions have remained the same, however, the maintenance schedule has been removed.

The area-wise/subgroup results are presented for the above-mentioned study scenarios. The differences in constraints are reported as the difference between the study with maintenance and the study without maintenance (Maintenance Study Constraints – No Maintenance Study Constraints = Difference). In 2027, the constraints calculated are pro-rata distributed amongst non-priority generators, and then priority generators should the constraint not be resolved by dispatching down non-priority generators, in their respective area/subgroup. However, in other years a grandfathered approach is employed. The details of the subgroups selected in each area are given in each area specific report.

The percentage difference is given in Figure 5-4 and Table 5-1 and for all maintenance sensitivities. This is followed by the GWh difference tables (Table 5-2, Table 5-3, Table 5-4, and Table 5-5) for each maintenance sensitivity scenario.

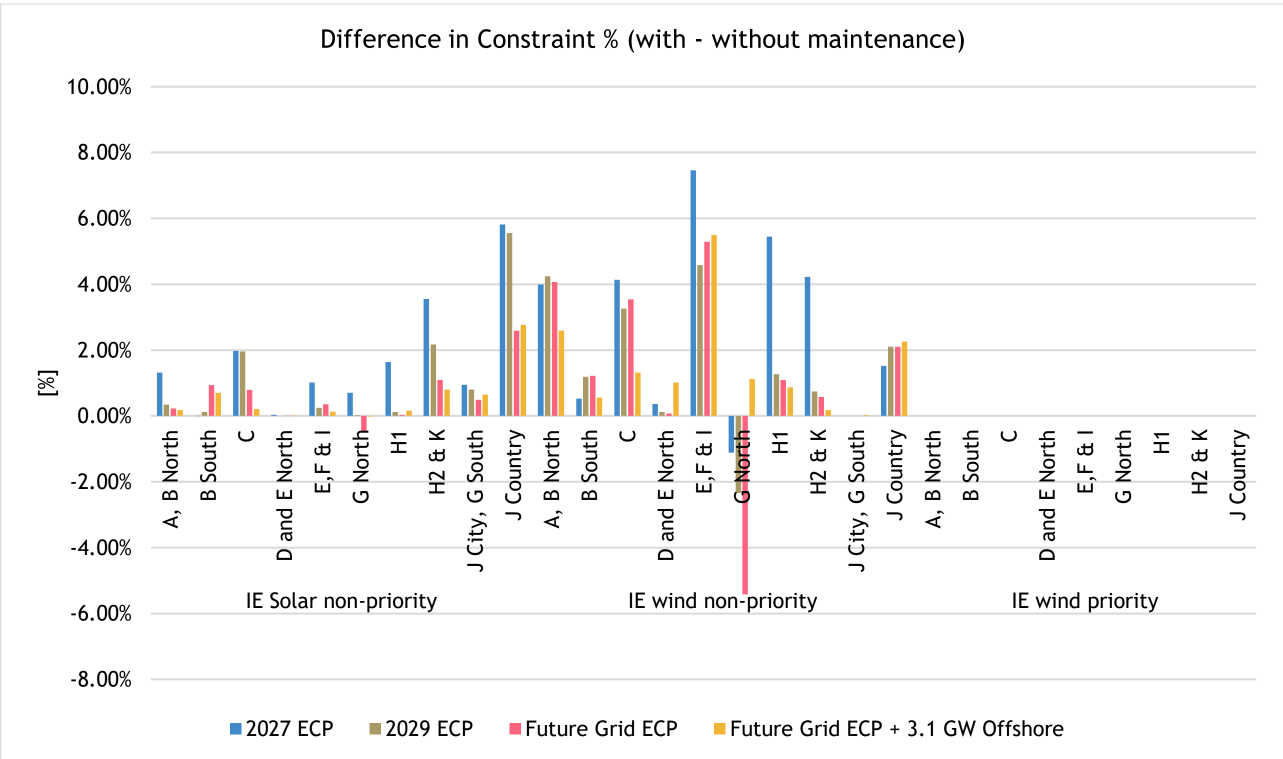

Figure 5-4 Difference in Constraint Percentage (with - without maintenance)

Generation Category	Subgroup	2027 ECP	2029 ECP	Future Grid ECP	Future Grid ECP + 3.1 GW Offshore
IE Solar non-priority	A, B North	1%	0%	0%	0%
	B South	0%	0%	1%	1%
	C	2%	2%	1%	0%
	D and E North	0%	0%	0%	0%
	E,F & I	1%	0%	0%	0%
	G North	1%	0%	0%	0%
	H1	2%	0%	0%	0%
	H2 & K	4%	2%	1%	1%
	J City, G South	1%	1%	0%	1%
	J Country	6%	6%	3%	3%
IE wind non-priority	A, B North	4%	4%	4%	3%
	B South	1%	1%	1%	1%
	C	4%	3%	4%	1%
	D and E North	0%	0%	0%	1%
	E,F & I	7%	5%	5%	5%
	G North	-1%	-2%	-5%	1%
	H1	5%	1%	1%	1%
	H2 & K	4%	1%	1%	0%
	J City, G South	0%	0%	0%	0%
	J Country	2%	2%	2%	2%
IE wind priority	A, B North	0%	0%	0%	0%
	B South	0%	0%	0%	0%
	C	0%	0%	0%	0%
	D and E North	0%	0%	0%	0%
	E,F & I	0%	0%	0%	0%
	G North	0%	0%	0%	0%
	H1	0%	0%	0%	0%
	H2 & K	0%	0%	0%	0%
	J Country	0%	0%	0%	0%

Table 5-1 Difference in Constraint Percentage (with - without maintenance)

Generation Category	Subgroup	Surplus + Curtailment (GWh)	Constraint without Maintenance (GWh)	Difference in Constraint with and without Maintenance (GWh)
IE Solar non-priority	A, B North	4	0	0
	B South	2	0	0
	C	493	4	18
	D and E North	102	0	0
	E,F & I	237	2	10
	G North	188	16	4
	H1	317	21	12
	H2 & K	497	25	56
	J City, G South	388	51	15
	J Country	932	687	97
IE wind non-priority	A, B North	998	573	72
	B South	240	11	2
	C	425	34	44
	D and E North	135	0	1
	E,F & I	345	2	30
	G North	130	42	-2
	H1	423	49	18
	H2 & K	328	8	30
	J Country	773	1019	26
IE wind priority	A, B North	156	336	42
	B South	183	16	2
	C	6	6	8
	D and E North	15	0	1
	E,F & I	310	5	80
	G North	75	46	-2
	H1	182	76	28
	H2 & K	37	6	20
	J Country	8	130	3

Table 5-2 Area subgroup GWh difference in constraint for 2027 ECP

Generation Category	Subgroup	Surplus + Curtailment (GWh)	Constraint without Maintenance (GWh)	Difference in Constraint with and without Maintenance (GWh)
IE Solar non-priority	A, B North	3	0	0
	B South	1	0	0
	C	311	2	18
	D and E North	45	0	0
	E,F & I	156	5	3
	G North	102	6	0
	H1	159	29	1
	H2 & K	357	35	34
	J City, G South	171	34	13
	J Country	634	749	93
IE wind non-priority	A, B North	368	891	122
	B South	127	46	8
	C	202	68	41
	D and E North	44	0	1
	E,F & I	129	4	68
	G North	78	50	-9
	H1	184	41	11
	H2 & K	211	10	9
	J Country	458	1265	40
IE wind priority	A, B North	18	0	0
	B South	63	0	0
	C	1	0	0
	D and E North	8	0	0
	E,F & I	207	0	0
	G North	34	0	0
	H1	33	0	0
	H2 & K	21	0	0
	J Country	3	0	0

Table 5-3 Area subgroup GWh difference in constraint for 2029 ECP

Generation Category	Subgroup	Surplus + Curtailment (GWh))	Constraint without Maintenance (GWh)	Difference in Constraint with and without Maintenance (GWh)
IE Solar non-priority	A, B North	1	0	0
	B South	1	0	0
	C	158	5	7
	D and E North	30	0	0
	E,F & I	75	9	4
	G North	67	22	-3
	H1	84	45	0
	H2 & K	308	57	17
	J City, G South	104	68	8
	J Country	357	677	43
IE wind non-priority	A, B North	133	608	117
	B South	43	3	9
	C	83	110	44
	D and E North	25	0	0
	E,F & I	57	10	78
	G North	31	205	-20
	H1	74	71	9
	H2 & K	138	19	7
	J Country	189	1101	40
IE wind priority	A, B North	3	0	0
	B South	7	0	0
	C	0	0	0
	D and E North	2	0	0
	E,F & I	64	0	0
	G North	2	0	0
	H1	11	0	0
	H2 & K	10	0	0
	J Country	1	0	0

Table 5-4 Area subgroup GWh difference in constraint for Future Grid ECP

Generation Category	Subgroup	Surplus + Curtailment (GWh)	Constraint without Maintenance (GWh)	Difference in Constraint with and without Maintenance (GWh)
IE Solar non-priority	A, B North	3	0	0
	B South	2	0	0
	C	338	0	2
	D and E North	73	0	0
	E,F & I	184	7	1
	G North	146	1	0
	H1	222	30	1
	H2 & K	614	38	13
	J City, G South	264	17	10
	J Country	673	544	46
IE wind non-priority	A, B North	1047	360	74
	B South	359	1	4
	C	448	10	16
	D and E North	485	4	27
	E,F & I	321	95	81
	G North	138	12	4
	H1	404	87	7
	H2 & K	564	9	2
	J City, G South	842	76	2
	J Country	910	472	43
IE wind priority	A, B North	26	0	0
	B South	92	0	0
	C	2	0	0
	D and E North	7	0	0
	E,F & I	271	0	0
	G North	24	0	0
	H1	62	0	0
	H2 & K	35	0	0
	J Country	8	0	0

Table 5-5 Area subgroup GWh difference in constraint for Future Grid + 3.1 GW Offshore

Appendix A - Network Reinforcement & Maintenance

A.1 Reinforcements in 2027

The table below lists the reinforcements, additional to the current network, that are included in the 2027 study scenario.

Project Classification	Project Name	Year
Uprate	Arva - Carrick-on-Shannon 110 kV line uprate	2027
Uprate	Bandon Dunmanway 110 kV circuit thermal capacity	2027
Demand Connection	Belcamp Shellybanks 220 kV Cable	2027
Uprate	Binbane - Cathleen's Fall 110 kV Line uprate	2027
New static device (DLR)	Cashla - Dalton 110 kV circuit 1 (DLR)	2027
Uprate	Cashla-Salthill 110 kV Thermal Uprate	2027
Uprate	Castlebar-Cloon 110 kV Line Uprate	2027
New static device (DLR)	Cathaleens Fall - Coraclassy 110 kV circuit 1 (DLR)	2027
Uprate	Coolnabacky - Portlaoise 110 kV line uprate	2027
Uprate	Crane - Wexford 110 kV Line uprate	2027
Uprate	Dalton 110 kV Busbar	2027
Uprate	Derryiron 110 kV Busbar Uprate	2027
Uprate	Drybridge - Oldbridge - Platin 110 kV line uprate	2027
Uprate	Flagford - Sliabh Bawn 110 kV circuit uprate	2027
Modification	Galway 110 kV Station Redevelopment Project	2027
Uprate	Glenree - Moy 110 kV Line Uprate	2027
Uprate	Gorman - Platin 110 kV line uprate	2027
Uprate	Kinnegad 110 kV station, Derryiron 110 kV bay conductor uprate	2027
Uprate	Lanesboro - Mullingar 110 kV Thermal Uprate	2027
Uprate	Lanesboro – Sliabh Bawn 110 KV Line Uprate	2027
Uprate	Laois Kilkenny (Coolnabacky) 400 kV Station - New Station & Associated Lines & Station Works	2027
New static device (DLR)	Lisheen - Thurles 110 kV	2027
Uprate	Louth - Rathrussan 110 kV No 1 Line Uprate	2027
Uprate	Maynooth - Woodland 220 kV line uprate	2027
Generation Connection	Moneypoint Synchronous Condenser	2027
New	New 400 220 kV Transformer for Moneypoint Sub-Station	2027
Replacement	New Ballyvouskill 220-110 kV Transformer	2027
Uprate	Newbridge - Cushaling 110 kV line, Stations bay conductors and lead-in conductor uprate	2027
Replacement	Prospect Tarbert 220 kV Cable Replacement Project	2027
Uprate	Sligo 110 kV Station - Shrananagh 1 & 2 Bay uprates	2027
Uprate	Thornsberry 110KV Station Busbar uprate	2027

Table A-1 Reinforcements included in the 2027 study

A.2 Reinforcements in 2029

The table below lists the network reinforcements included in the 2029 study scenario, additional to the network in the 2026 study scenario.

Project Classification	Project Name	Year
New static device (DLR)	Ardnacrusha - Ennis 110kV circuit DLR and related works	2029
Uprate	Bandon Raffeen 110 kV circuit thermal capacity	2029
Uprate & DLR	Baroda - Monread 110 kV circuit (DLR)	2029
New static device (DLR)	Baroda - Newbridge 110 kV circuit (DLR)	2029
Uprate	Cahir - Barrymore 110 kV circuit	2029
Uprate	Castlebar - Dalton 110 kV	2029
New	Cross Shannon 400 kV Cable	2029
Uprate	Derryiron - Thornsberry 110 kV Line Uprate	2029
Uprate	Drumkeen - Clogher 110 kV circuit	2029
New static device (DLR)	Drumline - Ennis 110 kV circuit (DLR)	2029
New	Dunstown 400 kV Series Capacitor	2029
New	Flagford Sligo Capacity Needs*	2029
Upgrade	Killonan 220 kV Station Refurbishment	2029
Uprate	Knockraha - Barrymore 110 kV circuit	2029
New static device (DLR)	Lisdrum - Louth 110 kV	2029
New static device (DLR)	Meath Hill - Louth 110 kV	2029
New	Moneypoint 400 kV Series Capacitor	2029
New	New 400 kV Strategic Spare Transformer (Dunstown)	2029
New	North Connacht 110 kV Project*	2029
New	North South 400 kV Interconnector - RoI	2029
Uprate	Oldstreet - Woodland 400 kV circuit	2029
New	Oldstreet-Woodland 400 kV Series Capacitor	2029

Table A-2 Reinforcements included in the 2029 study scenario, additional to 2027 study reinforcements

A.3 Reinforcements in Future Grid

The table below lists the reinforcements, additional to the current network, that are included in the Future Grid study scenario.

Project Type	Project	Year
New circuit	Binbane - Clogher - Cathaleen's Fall 110 kV Clogher tie-in	Future Grid
New circuit	Clogher - Srananagh 220 kV circuit	Future Grid
Uprate	Coleraine - Coolkeeragh 110 kV circuit	Future Grid
Uprate	Coolkeeragh - Killymallaght 110 kV circuit	Future Grid
Uprate	Coolkeeragh - Limavady 110 kV circuit	Future Grid
Uprate	Coolkeeragh - Strabane 110 kV circuit	Future Grid
Uprate	Letterkenny - Golagh T 110 kV	Future Grid
Uprate	Letterkenny - Strabane 110 kV	Future Grid
New static device (DLR)	Cashla - Dalton 110 kV circuit 1	Future Grid
Upvoltage	Flagford Sligo Capacity Needs	Future Grid
Uprate	Galway - Salthill 110 kV circuit	Future Grid
Uprate	Sligo - Srananagh 110 kV circuit 3	Future Grid
Uprate	Athlone - Lanesboro 110 kV circuit	Future Grid
Upvoltage	Flagford - Srananagh 110 kV circuit	Future Grid
Uprate	Bandon - Dunmanway 110 kV circuit	Future Grid
Uprate	Drybridge - Louth 110 kV circuit	Future Grid
Uprate	Gorman - Maynooth 220 kV	Future Grid
Uprate	Louth - Oriel 220 kV circuit	Future Grid
Uprate	Lisheen - Thurles 110 kV	Future Grid
Upvoltage	Arklow - Ballybeg - Carrickmines 220 kV circuit	Future Grid
Uprate	Athy - Carlow 110 kV circuit	Future Grid
Uprate	Carlow - Kellis 110 kV circuit 1	Future Grid
Uprate	Carlow - Kellis 110 kV circuit 2	Future Grid
Uprate	Great Island - Kellis 220 kV circuit	Future Grid
New Transformer	Great Island 220/110 transformer No.3	Future Grid
Uprate	Killoteran - Waterford 110 kV circuit	Future Grid
Uprate	Baroda - Monread 110 kV circuit	Future Grid
Uprate	Corduff - Blundelstown - Mullingar 110 kV	Future Grid
Uprate	Cushaling - Newbridge 110 kV circuit 1	Future Grid
Uprate	Derryiron - Maynooth 110 kV circuit	Future Grid
Uprate	Finglas - North Wall 220 kV circuit	Future Grid
Uprate	Blake Maynooth Newbridge Uprate	Future Grid
New circuit	Inchicore - Carrickmines 220 kV circuit	Future Grid
Uprate	Kilteel - Maynooth 110 kV circuit	Future Grid
Uprate	Maynooth - Castlelost 220 kV	Future Grid
Uprate	Maynooth - Griffinrath 110 kV circuit	Future Grid
Uprate	Maynooth - Rinawade 110 kV circuit	Future Grid
Uprate	Maynooth - Shannonbridge 220 kV circuit	Future Grid
Uprate	Maynooth - Timahoe 110 kV circuit	Future Grid
Uprate	North Wall - Poolbeg 220 kV circuit	Future Grid
Uprate	Poolbeg - Carrickmines 220 kV circuit	Future Grid
Uprate	Poolbeg South - Inchicore 220 kV circuit 1	Future Grid
Uprate	Poolbeg South - Inchicore 220 kV circuit 2	Future Grid
Uprate	Rinawade - Dunfirth 110 kV circuit	Future Grid
New circuit	Woodland - Finglas 400 kV cable cct	Future Grid
Uprate	Woodland - Oriel 220 kV circuit	Future Grid
Uprate	Drumnakelly - Tamnamore 110 kV circuits 1 & 2	Future Grid
Uprate	Lisburn - Tandragee 1 110 kV	Future Grid
Uprate	Lisburn - Tandragee 2 110 kV	Future Grid
New static device (DLR)	Magherakeel - Omagh circuit 1	Future Grid
New circuit	Mid Antrim Upgrade	Future Grid
New circuit	Mid-Tyrone Project	Future Grid

Project Type	Project	Year
New Substation	New 275 kV substation in South East Antrim	Future Grid
Uprate	Omagh - Strabane 110 kV circuit 2	Future Grid

Table A-3 Reinforcements included in the Future Grid Study

A.4 Maintenance within the PLEXOS Modelling

The table below outlines the representative transmission outage schedule applied within the PLEXOS model for this study.

Child Object	Time slice	Category
Ballylumford Kells 275 NI	M8	NI
Coleraine Coolkeeragh 110 NI	M8	NI
Kells_110_81520_KEL_275_1	M5	NI
Tandragee 110 275 ckt 2 NI	M7	NI
Aghada - Glanagow_220_1	M4	IE
Aghada - Raffeen_220_1	M6	IE
Arklow - Carrickmines_220_1	M3	IE
Arva - Carrick on Shannon_110_1	M8	IE
Arva - Navan_110_1	M5	IE
Arva - Shankill_110_1	M7	IE
Carlow - Kellis_110_1	M3	IE
Carrick on Shannon - Flagford_110_1	M9	IE
Carrickmines - Dunstown_220_1	M9	IE
Carrickmines - Irishtown_220_1	M10	IE
Carrickmines - Poolbeg_220_1	M5	IE
Carrigadrohid - Kilbarry_110_1	M11	IE
Cashla - Cloon_110_1	M3	IE
Cashla - Flagford_220_1	M11	IE
Cashla - Galway_110_1	M6	IE
Cashla - Prospect_220_1	M4	IE
Castlebagot - Maynooth 220_1	M10	IE
Castlebar - Cloon_110_1	M5	IE
Cathaleen's Fall - Srananagh_110_1	M10	IE
Clashavoon - Knockraha_220_1	M8	IE
Clashavoon - Macroom_110_1	M5	IE
Cloon - Lanesboro110_1	M4	IE
Coolnabacky - Moneypoint_380_1	M4	IE
Corduff - Cruiserath 220 1	M11	IE
Corduff - Ryebrook_110_1	M8	IE
Corduff - Woodland_220_1	M7	IE
Cullenagh - Great Island_220_1	M5	IE
Cullenagh - Knockraha_220_1	M9	IE
Cullenagh - Waterford_110_1	M3	IE
Cushaling - Portlaoise_110_1	M3	IE
Derryiron - Kinnegad_110_1	M4	IE
Drybridge - Gorman_110_1	M4	IE
Drybridge - Louth_110_1	M5	IE
Dunstown - Kellis_220_1	M8	IE
Dunstown - Maynooth_a_220_2	M9	IE
Flagford - Louth_220_1	M3	IE
Flagford - Sligo_110_1	M6	IE
Flagford - Srananagh_220_1	M4	IE
Glanagow - Raffeen_220_1	M7	IE
Gorman - Louth_220_1	M10	IE

Child Object	Time slice	Category
Gorman - Maynooth_220_1	M4	IE
Gorman - Navan_110_1	M9	IE
Gorman - Platin_110_1	M6	IE
Great Island - Kellis_220_1	M6	IE
Great Island - Lodgewood_220_1	M7	IE
Great Island - Waterford_110_1	M9	IE
Inchicore - Poolbeg_220_1	M11	IE
Killonan - Kilpaddoge_220_1	M10	IE
Killonan - Knockraha_220_1	M11	IE
Killonan - Limerick_110_1	M4	IE
Killonan - Shannonbridge_220_1	M9	IE
Kilpaddoge - Pollagh_110_1	M11	IE
Kilpaddoge - Tarbert_220_1	M3	IE
Kilpaddoge - Tralee_110_1	M11	IE
Knockraha - Raffeen_220_1	M8	IE
Maynooth - Blake-T_110_1	M5	IE
Maynooth - Shannonbridge_220_1	M10	IE
Newbridge - Portlaoise_110_1	M7	IE
Oldstreet - Woodland_380_1	M6	IE
Prospect - Tarbert_220_1	M3	IE
Raffeen - Trabeg_110_1	M7	IE
Sligo - Srananagh_110_1	M10	IE
Thurles - Ikerrin-T_110_1	M6	IE
Arklow T2102	M9	Transformer
Carrickmines T2101	M8	Transformer
Carrickmines T2102	M11	Transformer
Cashla T2101	M9	Transformer
Castlebagot T2101	M4	Transformer
Clashavoon T2102	M3	Transformer
Cullenagh T2101	M4	Transformer
Dunstown T4201	M5	Transformer
Dunstown T4202	M11	Transformer
Finglas T2101	M6	Transformer
Flagford T2101	M5	Transformer
Inchicore T2101	M7	Transformer
Killonan T2104	M8	Transformer
Kilpaddoge T2101	M7	Transformer
Knockraha T2101	M6	Transformer
Knockraha T2102	M10	Transformer
Louth T2101	M8	Transformer
Moneypoint T4202	M10	Transformer
Woodland T4201	M7	Transformer

Table A-4 Representative Transmission Outage Schedule

Appendix B - Generator Details

The following generator information is included in this Appendix:

- Generator Type for each Generation Scenario
- Generator Type by Area for each Generation Scenario

A full list of generators included in the study is published separately on the ECP-2.4 constraint forecast webpage[18].

Note: the tables in the following section include both Ireland and Northern Ireland generation.

[18] https://www.eirgrid.ie/industry/customer-information/ecp-constraint-forecast-reports#ecp-2.4-constraint-reports-for-solar-and-wind

B.1 Generation Type for each Generator Scenario

The table below shows existing and expected wind, wind offshore, solar, wave, battery, and other technologies (other technologies include gas, diesel, biomass, biogas, CHP, LFG, and Anaerobic Digester (AD) plants) in both Ireland and Northern Ireland, which were included in this analysis.

Type	Initial (MW)	50% (MW)	ECP (MW)	ECP + 3.1 GW Offshore (MW)	ECP + 5 GW Offshore (MW)
Battery	1,096	2,888	4,679	4,679	4,679
Solar	1,783	4,720	7,657	7,657	7,657
Wave	-	5	10	10	10
Wind	6,715	8,322	9,929	9,929	9,929
Offshore wind	25	25	25	3,099	5,525
Other technologies	53	174	295	295	295
Total	**9,673**	**16,134**	**22,595**	**25,669**	**28,095**

Table B-1 Total Generation per Generation Type

B.2 Generation Type by Area for each Generator Scenario

The table below shows existing and expected wind, wind offshore, solar, wave, battery, and other technologies (other technologies include: biomass, biogas, CHP, LFG, and AD plants) in both Ireland and Northern Ireland, which were included in this analysis.

Type and Area	Initial (MW)	50% (MW)	ECP (MW)	ECP + 3.1 GW Offshore (MW)	ECP + 5 GW Offshore (MW)
Battery	**1,096**	**2,888**	**4,679**	**4,679**	**4,679**
A	3	41	78	78	78
B	11	253	496	496	496
C	263	324	385	385	385
D	-	15	30	30	30
E	40	210	380	380	380
G	110	247	385	385	385
H1	-	133	265	265	265
H2	55	277	499	499	499
I	178	219	260	260	260
J	236	441	646	646	646
K	-	58	115	115	115
NI	200	670	1,140	1,140	1,140
Solar	**1,783**	**4,720**	**7,657**	**7,657**	**7,657**
A	-	20	40	40	40
B	43	141	240	240	240
C	122	366	610	610	610
D	-	120	239	239	239
E	148	352	556	556	556
F	27	37	47	47	47
G	220	718	1,216	1,216	1,216
H1	70	339	608	608	608
H2	297	698	1,099	1,099	1,099
I	43	187	331	331	331
J	446	1,085	1,724	1,724	1,724
K	123	208	293	293	293
NI	244	448	652	652	652
Wave	**-**	**5**	**10**	**10**	**10**
B	-	5	10	10	10
Wind	**6,715**	**8,322**	**9,929**	**9,929**	**9,929**
A	825	955	1,085	1,085	1,085
B	794	929	1,064	1,064	1,064
C	131	350	570	570	570
D	312	363	414	414	414
E	1,488	1,538	1,588	1,588	1,588
F	215	219	223	223	223
G	279	279	279	279	279
H1	554	632	709	709	709

H2	345	497	650	650	650
I	8	8	8	8	8
J	199	399	598	598	598
K	61	103	146	146	146
NI	1,504	2,050	2,596	2,596	2,596
Offshore wind	**25**	**25**	**25**	**3,099**	**5,525**
E	-	-	-	450	450
G	-	-	-		370
H2	25	25	25	25	1,203
I	-	-	-		378
J	-	-	-	2,624	2,624
NI	-	-	-	-	500
Other technologies	**53**	**174**	**295**	**295**	**295**
B	2	63	124	124	124
E	10	15	20	20	20
F	11	11	11	11	11
G	20	20	20	20	20
J	8	62	117	117	117
K	3	3	3	3	3
Grand Total	**9,673**	**16,134**	**22,595**	**25,669**	**28,095**

Table B-2 Generation Type by Area for each Generator Scenario

B.3 Generation List by Type, Node and Name

A full list of IE renewable generation included in the study is published separately on the ECP-2.4 constraint forecast webpage[19] which includes existing and expected wind, wind offshore and solar sorted A to Z by name.

These are in addition to the new large conventional generators, which are listed in EirGrid and SONI's All-Island Resource Adequacy Assessment 2025 - 2034.

[19] https://www.eirgrid.ie/industry/customer-information/ecp-constraint-forecast-reports#ecp-2.4-constraint-reports-for-solar-and-wind

Appendix C - Contingencies and Lines Overloading

For different study scenarios, there were several transmissions boundaries that limit the power flow. Some of the main overload and contingency pairs binding for more than 200 hours for the two study years (2027 ECP (All) and 2029 ECP (All)) can be seen below.

C.1 Year 2027

Line	Contingency	Hours Range
Line (Bellacorick - Castlebar_110_1)	Loss of Cunghill Sligo 110	4250-4500
Line (Maynooth - Timahoe_110_1)	Loss of Derryiron Kinnegad 110	3000-3250
Line (Maynooth - Blake-T_110_1)	Loss of Castlebagot Maynooth 220 1	3000-3250
Line (Knockraha - Barrymore-T_110_1)	Loss of Cahir-Doon 110	2250-2500
Interface (IE to NI NTC)	Base	2250-2500
Line (Finglas - Mooretown_220_1)	Loss of Corduff Mooretown 220 1	2000-2250
Line (Flagford - Sligo_110_1)	Loss of Carrick on Shannon - Arigna T 110	1750-2000
Line (Rinawade - Dunfirth-T_110_1)	Loss of Corduff Blundelstown 110	1750-2000
Line (Maynooth - Blake-T_110_1)	Loss of Oldstreet Woodland 400	1500-1750
Line (Maynooth - Rinawade_110_1)	Loss of Corduff Blundelstown 110	1500-1750
Line (Drumnakelly Tamnamore_110_1 NI)	Loss of Coolkeeragh Magherafelt 275 NI	1500-1750
Line (Letterkenny - Golagh-T_110_1)	Loss of Binbane - Cath Fall 110	1500-1750
Line (Galway - Salthill_110_1)	Base	1500-1750
Line (Coolkeeragh Strabane_110_1 NI)	Loss of Coolkeeragh Killymallaght 110 NI	1500-1750
Line (Coolkeeragh Limavady_110_1 NI)	Loss of Kells Rasharkin 110 NI	1500-1750
Line (Clahane - Trien_110_1)	Loss of Kilpaddoge Knockanure 110	1250-1500
Line (Coleraine Coolkeeragh 110 NI)	Loss of Kells Rasharkin 110 NI	1250-1500
Line (Bellacorick - Castlebar_110_1)	Loss of Cunghill Glenree 110	1250-1500
Line (Lanesboro coupler_110_1)	Loss of Flagford Louth 220	1000-1250
Line (Carrick on Shannon - Arigna-T_110_1)	Loss of Flagford-Srananagh 220 circuit 1	1000-1250
Line (Corduff - Macetown_110_1)	Loss of Paddock Woodland 220	750-1000
Line (Corduff - Macetown_110_1)	Loss of Arodstown to Maynooth 220	750-1000
Line (Derryiron - Kinnegad_110_1)	Loss of Maynooth - Timahoe 110	750-1000
Line (Cathaleens Fall - Srananagh_110_1)	Loss of CF-Srananagh 110 2	750-1000
Line (Maynooth - Blake-T_110_1)	Loss of Derryiron Kinnegad 110	750-1000
Line (Corduff - Macetown_110_1)	Loss of Maynooth - Timahoe 110	750-1000
Line (Cullenagh - Waterford_110_1)	Loss of Cullenagh-Great Island 220	750-1000
Line (Corduff - Macetown_110_1)	Loss of Shellybanks coupler 220	750-1000
Line (Maynooth - Rinawade_110_1)	Loss of Bracklyn Mullingar 110	750-1000
Line (Cahir - Barrymore-T_110_1)	Loss of Cahir-Doon 110	750-1000
Line (Cauteen - Killonan_110_1)	Loss of Cauteen Tipperary 110	750-1000
Line (Arklow T2101)	Loss of Arklow 220-110 2	750-1000
Line (Maynooth - Timahoe_110_1)	Loss of Derryiron Thornsberry 110	750-1000
Line (Killoteran - Waterford_110_1)	Loss of Cullenagh-Waterford 110	500-750
Line (Cahir - Doon_110_1)	Loss of Cullenagh-Knockraha 220	500-750

Line (Killoteran - Waterford_110_1)	Loss of Cullenagh-Great Island 220	500-750
Line (Carrick on Shannon - Arigna-T_110_1)	Loss of Srananagh 220-110 2	500-750
Line (Great Island T2102)	Loss of Cullenagh-Great Island 220	500-750
Line (Carlow - Kellis_110_2)	Loss of Dunstown-Kellis 220	500-750
Line (Corduff - Macetown_110_1)	Loss of Baltrasna Corduff 110	500-750
Line (Kells Rasharkin 110 ckt 1 NI)	Loss of Coolkeeragh Magherafelt 275 NI	500-750
Line (Derryiron - Timahoe_110_1)	Loss of Derryiron Kinnegad 110	500-750
Line (Maynooth - Rinawade_110_1)	Loss of Blundlestown Fosterstown 110	500-750
Line (Drybridge - Louth_110_1)	Loss of Gorman Louth 220	500-750
Line (Maynooth - Rinawade_110_1)	Loss of Maynooth - Timahoe 110	500-750
Line (Castlebar - Dalton_110_1)	Loss of Cunghill Sligo 110	500-750
Line (Corduff - Macetown_110_1)	Loss of Derryiron Timahoe 110	500-750
Line (Bellacorick - Castlebar_110_1)	Loss of Firlough Glenree 110	500-750
Line (Corduff - Mooretown_220_1)	Loss of Finglas Mooretown 220	500-750
Line (Clahane - Tralee_110_1)	Loss of Kilpaddoge Knockanure 110	500-750
Line (Cathaleens Fall - Srananagh_110_2)	Loss of CF-Srananagh 110 1	500-750
Line (Maynooth - Timahoe_110_1)	Loss of Cushaling Newbridge 110	500-750
Line (Great Island - Kellis_220_1)	Loss of Arklow Carrickmines 220 1	250-500
Line (Rinawade - Dunfirth-T_110_1)	Loss of Bracklyn Mullingar 110	250-500
Line (Rinawade - Dunfirth-T_110_1)	Loss of Bracklyn Fosterstown 110	250-500
Line (Knockraha - Barrymore-T_110_1)	Loss of Killonan Knockraha 220	250-500
Line (Maynooth - Blake-T_110_1)	Loss of coolnabacky dunstown 400	250-500
Line (Maynooth - Rinawade_110_1)	Loss of Bracklyn Fosterstown 110	250-500
Line (Corduff - Macetown_110_1)	Loss of Castlebagot Maynooth 220 1	250-500
Line (Corduff - Macetown_110_1)	Loss of Corduff-Ryebrook 110	250-500
Line (Drybridge - Louth_110_1)	Loss of Paddock Woodland 220	250-500
Line (Arklow T2101)	Loss of Lodgewood 220-110 1	250-500
Line (Arodstown - Maynooth_220_1)	Loss of Paddock Woodland 220	250-500
Line (Arklow T2101)	Loss of Arklow Lodgewood 220	250-500
Line (Blundelstown - Corduff_110_1)	Loss of Clonfad to Kinnegad 110	250-500
Line (Corduff - Macetown_110_1)	Loss of Arodstown to gorman 220	250-500
Line (Knockraha - Barrymore-T_110_1)	Loss of Cullenagh to Mothel 110	250-500
Line (Maynooth - Blake-T_110_1)	Loss of Kinnegad Harristown to Dunfi T 110	250-500
Line (Knockraha - Barrymore-T_110_1)	Loss of Ballynahulla Knockanure 220	250-500
Line (Knockraha - Barrymore-T_110_1)	Loss of Ballydine Mothel 110	250-500
Line (Cahir - Barrymore-T_110_1)	Loss of Ballynahulla Knockanure 220	250-500
Line (Maynooth - Blake-T_110_1)	Loss of Baroda Newbridge 110	250-500
Line (Maynooth - Blake-T_110_1)	Loss of gen Dublin Bay	250-500
Line (Corduff - Macetown_110_1)	Loss of Oldstreet Woodland 400	250-500
Line (Bellacorick - Castlebar_110_1)	Loss of Firlough Moy 110	250-500
Line (Clashavoon - Macroom_110_1)	Loss of Clashavoon Knockraha 220	250-500
Line (Derryiron - Thornsberry_110_1)	Loss of Cushaling - Mount Lucas 110	250-500
Line (Cathaleens Fall - Srananagh_110_2)	Loss of CF-Corraclassy 110	250-500
Line (Coleraine Rasharkin_110_1)	Loss of Kells Rasharkin 110 NI	250-500
Line (Athy - Carlow_110_1)	Loss of Arklow Carrickmines 220 1	250-500
Line (Cushaling - Newbridge_110_1)	Loss of Derryiron Timahoe 110	250-500
Line (Knockraha - Barrymore-T_110_1)	Loss of Cauteen Killonan 110	250-500

Line (Derryiron - Thornsberry_110_1)	Loss of Mount Lucas - Thornsberry 110	250-500
Line (Great Island - Kellis_220_1)	Loss of Great Island - Lodgewood 220	250-500
Line (Corduff - Macetown_110_1)	Loss of Clonee Woodland 220	250-500
Line (Dunstown T4202)	Loss of Oldstreet Woodland 400	250-500
Line (Great Island T2102)	Loss of Great Island - Lodgewood 220	<250
Line (Corduff - Macetown_110_1)	Loss of gen Dublin Bay	<250
Line (Moneypoint T4201)	Base	<250
Line (Corduff - Macetown_110_1)	Loss of Louth-Oriel 220	<250
Line (Dalton coupler_110_1)	Loss of Cunghill Sligo 110	<250
Line (Great Island - Rosspile_110_1)	Loss of Arklow Carrickmines 220 1	<250
Line (Kells Rasharkin 110 ckt 1 NI)	Loss of Coleraine Rasharkin 110 NI	<250
Line (Carrickmines - Poolbeg_220_1)	Loss of gen Dublin Bay	<250
Line (Baroda - Monread_110_1)	Loss of Mount Lucas - Thornsberry 110	<250
Line (Moneypoint T4201)	Loss of Moneypoint 400-220 2	<250
Line (Cashla - Dalton_110_1)	Loss of Cunghill Sligo 110	<250
Line (Cahir - Barrymore-T_110_1)	Loss of Cullenagh-Knockraha 220	<250

Table C-1 Binding contingency and overloading lines in 2027 ECP (All) study

C.2 Year 2029

Line	Contingency	Hours Range
Line (Belfast North - Donegall 110 ckt 2 NI)	loss of Castlereagh 275 110 circuit 1	7000-7250
Line (Maynooth - Timahoe_110_1)	Loss of Derryiron Kinnegad 110	3000-3250
Line (Donegal Hannahstown_110_2 NI)	loss of Castlereagh 275 110 circuit 1	2250-2500
Line (Finglas - Mooretown_220_1)	Loss of Corduff Mooretown 220 1	2250-2500
Line (Maynooth - Blake-T_110_1)	Loss of Castlebagot Maynooth 220 1	2000-2250
Line (Maynooth - Blake-T_110_1)	Loss of coolnabacky dunstown 400	2000-2250
Line (Lanesboro coupler_110_1)	Loss of Flagford Louth 220	2000-2250
Line (Galway - Salthill_110_1)	Base	2000-2250
Line (Maynooth - Rinawade_110_1)	Loss of Corduff Blundelstown 110	1750-2000
Line (Cunghill - Sligo_110_1)	Loss of Bellacorick-Castlebar 110	1750-2000
Line (Corduff - Macetown_110_1)	Loss of Maynooth - Timahoe 110	1250-1500
Line (Clahane - Trien_110_1)	Loss of Kilpaddoge Knockanure 110	1250-1500
Line (Maynooth - Blake-T_110_1)	Loss of Derryiron Kinnegad 110	1250-1500
Line (Carrick on Shannon - Arigna-T_110_1)	Loss of Flagford-Srananagh 220 circuit 1	1000-1250
Line (Cauteen - Killonan_110_1)	Loss of Cauteen Tipperary 110	1000-1250
Line (Knockraha - Barrymore-T_110_1)	Loss of Cahir-Doon 110	1000-1250
Line (Letterkenny - Golagh-T_110_1)	Loss of Binbane - Cath Fall 110	1000-1250
Line (Carrick on Shannon - Arigna-T_110_1)	Loss of Srananagh 220-110 2	1000-1250
Line (Corduff - Macetown_110_1)	Loss of Arodstown to Maynooth 220	1000-1250
Line (Cathaleens Fall - Srananagh_110_1)	Loss of CF-Srananagh 110 2	750-1000
Line (Derryiron - Kinnegad_110_1)	Loss of Maynooth - Timahoe 110	750-1000
Line (Maynooth - Timahoe_110_1)	Loss of Derryiron Thornsberry 110	750-1000
Line (Arklow T2101)	Loss of Arklow 220-110 2	750-1000
Line (Great Island - Kellis_220_1)	Loss of Arklow Carrickmines 220 1	750-1000
Line (Corduff - Macetown_110_1)	Loss of Corduff-Ryebrook 110	750-1000
Line (Rinawade - Dunfirth-T_110_1)	Loss of Corduff Blundelstown 110	750-1000
Line (Corduff - Macetown_110_1)	Loss of Shellybanks coupler 220	750-1000
Line (Bellacorick - Moy_110_1)	Loss of Bellacorick-Castlebar 110	750-1000
Line (Corduff - Macetown_110_1)	Loss of Derryiron Timahoe 110	750-1000
Line (Maynooth - Rinawade_110_1)	Loss of Bracklyn Mullingar 110	750-1000
Line (Dalton coupler_110_1)	Loss of Castlebar Cloon 110	750-1000
Line (Creagh Terrygowan 110 ckt 1 NI)	Loss of Coleraine Rasharkin 110 NI	750-1000
Line (Derryiron - Timahoe_110_1)	Loss of Derryiron Kinnegad 110	750-1000
Line (Corduff - Macetown_110_1)	Loss of Baltrasna Corduff 110	500-750
Line (Rinawade - Dunfirth-T_110_1)	Loss of Blundlestown Fosterstown 110	500-750
Line (Maynooth - Blake-T_110_1)	Loss of Kinnegad Harristown to Dunfi T 110	500-750
Line (Clashavoon - Macroom_110_1)	Loss of Clashavoon Knockraha 220	500-750
Line (Corduff - Macetown_110_1)	Loss of Arodstown to gorman 220	500-750
Line (Maynooth - Timahoe_110_1)	Loss of Cushaling Newbridge 110	500-750
Line (Lisdrum - Lislea 110 1)	Loss of Louth - Ratrussan 110	500-750
Line (Maynooth - Rinawade_110_1)	Loss of Blundlestown Fosterstown 110	500-750
Line (Maynooth - Rinawade_110_1)	Loss of Maynooth - Timahoe 110	500-750
Line (Great Island - Kellis_220_1)	Loss of Great Island - Lodgewood 220	500-750
Line (Killoteran - Waterford_110_1)	Loss of Cullenagh-Waterford 110	500-750

Line (Cathaleens Fall - Srananagh_110_2)	Loss of CF-Srananagh 110 1	500-750
Line (Carlow - Kellis_110_2)	Loss of Dunstown-Kellis 220	500-750
Line (Maynooth - Rinawade_110_1)	Loss of Bracklyn Fosterstown 110	500-750
Line (Corduff - Mooretown_220_1)	Loss of Finglas Mooretown 220	500-750
Line (Arklow T2101)	Loss of Lodgewood 220-110 1	500-750
Line (Bellacorick - Castlebar_110_1)	Loss of Bellacorick-Moy 110	500-750
Line (Maynooth - Blake-T_110_1)	Loss of Baroda Newbridge 110	500-750
Line (Clahane - Tralee_110_1)	Loss of Kilpaddoge Knockanure 110	500-750
Line (Athy - Carlow_110_1)	Loss of Arklow Carrickmines 220 1	500-750
Line (Athy - Carlow_110_1)	Loss of Dunstown-Kellis 220	250-500
Line (Corduff - Macetown_110_1)	Loss of Castlebagot Maynooth 220	250-500
Line (Rinawade - Dunfirth-T_110_1)	Loss of Bracklyn Fosterstown 110	250-500
Line (Arklow T2101)	Loss of Arklow Lodgewood 220	250-500
Line (Flagford - Sligo_110_1)	Loss of Carrick on Shannon - Arigna T 110	250-500
Line (Rinawade - Dunfirth-T_110_1)	Loss of Bracklyn Mullingar 110	250-500
Line (Cunghill - Glenree_110_1)	Loss of Bellacorick-Castlebar 110	250-500
Line (Drumnakelly Tamnamore_110_1 NI)	Loss of Coolkeeragh Magherafelt 275 NI	250-500
Line (Cunghill - Sligo_110_1)	Moy - Tonroe_110	250-500
Line (Blundelstown - Corduff_110_1)	Loss of Clonfad to Kinnegad 110	250-500
Line (Killoteran - Waterford_110_1)	Loss of Cullenagh-Great Island 220	250-500
Line (Corduff - Macetown_110_1)	Loss of gen Dublin Bay	250-500
Line (Coolkeeragh Strabane_110_1 NI)	Loss of Coolkeeragh Killymallaght 110 NI	250-500
Line (Clonee - Woodland_220_1)	Loss of Corduff Woodland 220 1	250-500
Line (Lanesboro coupler_110_1)	Loss of Cashla-Flagford 220	250-500
Line (Bandon - Raffeen_110_1)	Loss of Clashavoon Knockraha 220	250-500
Line (Creagh Terrygowan 110 ckt 1 NI)	loss of kells 275 110 circuit 2	250-500
Line (Knockraha - Barrymore-T_110_1)	Loss of Cauteen Killonan 110	250-500
Line (Cathaleens Fall - Srananagh_110_2)	Loss of CF-Corraclassy 110	250-500
Line (Cushaling - Newbridge_110_1)	Loss of Derryiron Timahoe 110	250-500
Line (Clahane - Trien_110_1)	Loss of Kilpaddoge Tralee 110	250-500
Line (Coolkeeragh Limavady_110_1 NI)	Loss of Coleraine Coolkeeragh 110 NI	250-500
Line (Cunghill - Sligo_110_1)	Loss of Flagford Tonroe 110	250-500
Line (Great Island - Rosspile_110_1)	Loss of Arklow Carrickmines 220 1	250-500
Line (Kilbarry - Marina_110_1)	Loss of kilbarry marina 110	250-500
Line (Bellacorick - Castlebar_110_1)	Loss of Cunghill Sligo 110	250-500
Line (Drybridge - Louth_110_1)	Loss of Garballagh Platin 110	250-500
Line (Moy - Tawnaghmore_110_1)	Base	250-500
Line (Knockraha - Barrymore-T_110_1)	Loss of Killonan Knockraha 220	250-500
Line (Lysaghtstown- Midleton_110_1)	Loss of Knockraha to Midleton 110	250-500
Line (Aghada - Knockraha_220_1)	Loss of Aghada-Knockraha 220 circuit 2	<250
Line (Corduff - Macetown_110_1)	Loss of Clonfad to Kinnegad 110	<250
Line (Corduff - Macetown_110_1)	Loss of gen HN2	<250
Line (Drybridge - Louth_110_1)	Loss of Gorman Louth 220	<250
Line (Cushaling - Newbridge_110_1)	Loss of Maynooth - Timahoe 110	<250
Line (Omagh Strabane_110_2 NI)	Loss of Coolkeeragh Magherafelt 275 NI	<250
Line (Carlow - Kellis_110_2)	Loss of Carlow Kellis 110	<250
Line (Kilbarry - Mallow_110_1)	Loss of Charleville Killonan 110	<250

Line (Rosspile - Wexford_110_1)	Loss of Arklow Carrickmines 220 1	<250
Line (Dunstown - Turlough Hill 220_1)	Loss of gen GI4	<250

Table C-2 Binding contingency and overloading lines in 2029 ECP (All) study

Abbreviation and Terms

Active Power

The product of voltage and the in-phase component of alternating current measured in Megawatts (MW). When compounded with the flow of 'reactive power', measured in Megavolt-Amperes Reactive (Mvar), the resultant is measured in Megavolt-Amperes (MVA).

Busbar

The common connection point of two or more circuits.

Capacity Factor

The capacity factor of a generator is the ratio of the actual electrical energy output over a given period of time to the maximum possible electrical energy output over that period.

$$Capacity\ Factor = \frac{Energy\ Output}{Hours\ per\ year * Installed\ Capacity}$$

Combined Cycle Gas Turbine (CCGT)

This is a type of thermal generator that typically uses natural gas as a fuel source. It is a collection of gas turbines and steam units; where waste heat from the gas turbines(s) is passed through a heat recovery boiler to generate steam for the steam turbines.

Commission for Regulation of Utilities (CRU)

The CRU is the regulator for the electricity, natural gas and public water sectors in Ireland.

Constraint

The reduction in output of a generator due to network limits. Usually, constraints are local to a transmission bottleneck.

Contingency

The unexpected failure or outage of a system component, such as a generation unit, transmission line, transformer, or other electrical element. The transmission network is operated safe against the possible failure or outage of any system component. Hence, contingency usually refers to the possible loss of any system component. A contingency may also include multiple components when these are subject to common cause outages.

Curtailment

Curtailment is when the transmission system operators EirGrid and SONI ask generation to reduce their output to ensure system security is maintained. Usually, curtailment is shared across the whole system.

Demand

The amount of electrical power that customers consume, and which is measured in Megawatts (MW). In a general sense, the amount of power that must be transported from transmission network connected generation stations to meet all customers' electricity requirements.

Dispatch Balancing Costs (DBC)

Dispatch Balancing Costs refers to a number of payments related to the differences between generators' market position and their actual output. They include Constraint Payments, Uninstructed Imbalance

Payments and Generator Testing Charges. The Transmission System Operators (TSOs) are responsible for forecasting and managing Dispatch Balancing Costs.

Dynamic Line Rating (DLR)

Operational tool aimed at maximising electrical power transmission when environmental conditions allow it.

Enduring Connection Policy (ECP)

The Commission for Regulation of Utilities (CRU) has put in place a revised approach to issuing connection offers to generators. This approach is called the Enduring Connection Policy (ECP). With ECP, it is envisaged that batches of generator connection offers will issue on a periodic basis.

Enduring Connection Policy - 2 (ECP-2)

ECP-2 is the second stage of the CRU's development of enduring connection policy in Ireland. In June 2020 the CRU published their decision on ECP-2, this decision set policy for at least three batches of connection offers (ECP-2.1, ECP-2.2, ECP-2.3, and ECP-2.4).

Forced Outage Probability (FOP)

This is the statistical probability that a generation unit will be unable to produce electricity for non-scheduled reasons due to the failure of either the generation plant or supporting systems. Periods, when the unit is on scheduled outage, are not included in the determination of forced outage probability.

Generation Dispatch

This is the configuration of outputs from the connected generation units.

Interconnector

The electrical link, facilities and equipment that connect the transmission network of one power market to another.

Load flow

Study carried out to simulate the flow of power on the transmission system given a generation dispatch and system load.

A DC load flow is a study, which uses simplifying assumptions in relation to voltage and reactive power. DC load flow studies are used as part of an overarching study. For example, PLEXOS uses DC load flow because it is performing studies for every hour of every study year and is performing a large optimisation calculation for each of these.

Maximum Export Capacity (MEC)

The maximum export value (MW) provided in accordance with a generator's connection agreement. The MEC is a contract value that the generator chooses as its maximum output.

Megawatt (MW) and Gigawatt (GW)

Unit of power: 1 megawatt = 1,000 kilowatts = 106 joules / second
1 gigawatt = 1,000 megawatts

Megawatt Hour (MWh), Gigawatt Hour (GWh) and Terawatt Hour (TWh)

Unit of energy: 1 megawatt hour = 1,000 kilowatt hours = 3.6×10^9 joules
1 gigawatt hour = 1,000 megawatt hours
1 terawatt hour = 1,000 gigawatt hours

Operational Constraints/Limits

In order to operate a safe, secure, and stable electricity system, the TSO must operate the system within certain operational constraints/limits which include; maximum SNSP, maximum RoCoF, minimum level of system inertia, minimum number of conventional units, minimum levels of reserve. Conventional generator "must run" rules to ensure adequate system voltage and power flow control

PLEXOS

PLEXOS is a commercially available power system simulation tool used in this study to evaluate surplus, curtailment and constraint. PLEXOS is a detailed generation and transmission analysis program that has been widely used in the electricity industry for many years.

Rate of Change of Frequency (RoCoF)

As low inertia non-synchronous generators displace high inertia synchronous generators in system dispatch, then the system gets lighter. Then, for the loss of a large infeed (e.g., trip of an interconnector or generator), the system frequency will change more quickly.

RoCoF is the agreed limit to which the system is agreed to be operated and which generators, demand and system protection schemes are expected to manage. In Ireland, the TSOs are proposing to increase the RoCoF value. This will allow more renewable generation and may require confirmation by participants that they can meet the proposed RoCoF.

Short Run Marginal Cost (SRMC)

The instantaneous variable cost for a power plant to provide an additional unit of electricity, i.e., the cost of each extra MW it could produce excluding its fixed costs. The SRMC reflects the opportunity cost of the electricity produced, which is the economic activity that the generator forgoes to produce electricity. For example, in the case of a generator fuelled by gas, the opportunity cost includes the price of gas on the day that it is bidding in because if the generator is not producing electricity, it could sell its gas in the open market.

Surplus

Reduction of renewable generation to a level below its availability for surplus reasons is necessary when the total available generation exceeds system demand plus interconnector export flows. Surplus is applied through market processes prior to dispatch or balancing actions taken by the transmission system operator such as curtailment and constraint.

System Non-Synchronous Penetration (SNSP)

The introduction of large quantities of non-synchronous generators such as solar and wind poses challenges to a synchronous power system. For Ireland, a system non-synchronous penetration (SNSP) ratio is defined to help identify the system operational limits. The present allowable ratio is 75% but future system services arrangements and proposed amendments to system operation are expected to allow SNSP to increase in future years.

Total Dispatch Down

For the purpose of this report Total Dispatch Down is equivalent to the sum of surplus (generation self-reduction due to market position), plus curtailment (re-dispatch due to system operational constraints), plus constraint (re-dispatch due to network limitations).

Total Electricity Requirement (TER)

TER is the total amount of electricity required by a country. It includes all electricity exported by generating units, as well as that consumed on-site by self-consuming electricity producers, e.g., CHP.

Transmission Peak

The peak demand that is transported on the transmission network. The transmission peak includes an estimate of transmission losses.

Transmission System

The transmission system is a meshed network of high-voltage lines and cables (400 kV, 275 kV, 220 kV and 110 kV) for the transmission of bulk electricity supply around Ireland and Northern Ireland.

Transmission System Operator (TSO)

In the electrical power business, a transmission system operator is the licensed entity that is responsible for transmitting electrical power from generation plants to regional or local electricity distribution operators and Large Energy Users connected at the transmission level.

Uprating

A network reinforcement solution whereby an existing circuit's rating can be increased. This is achieved by increasing ground clearances and/or replacing conductor, together with any changes to terminal equipment, support structures and foundations.

Winter Peak

This is the maximum annual system demand. Historically this occurs in the winter period October to February, inclusive in Ireland and in the period November to February in Northern Ireland.

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