Constraint Forecast Studies for Enduring Connection Policy (ECP)

Methodology Statement

Applicable from ECP 2.5 onwards

Version 1.0

February 2026

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Revision	Date	Description
V1.0	10/02/2026	

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1 Contents

Abbreviations & Terms

BESS	Battery Energy Storage System
CRU	Commission for Regulation of Utilities
ECP	Enduring Connection Policy
ECP - GSS	Generation and System Services
GW	Giga watt
IC	Interconnector
IE	Ireland
NI	Northern Ireland
NDP	Network Delivery Portfolio
ORESS	Offshore Renewable Energy Support Scheme
RE-HUB	Renewable Hubs
RES	Renewable Energy Sources
SEM	Single Electricity Market
SOEF	Shaping Our Electricity Future
TER	Total Electricity Requirement
TSO	Transmission System Operator
MEC	Maximum Export Capacity
POR	Primary Operating Reserve
SOR	Secondary Operating Reserve
TOR	Tertiary Operating Reserve
LPF	Load Participation Factor
PSSe	Power System Simulation
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. $$Capacity\ Factor = \frac{Energy\ Output}{Hours\ per\ Year * Installed\ Capacity}$$
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.
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.
Future Grid	A future network scenario which includes reinforcement which are part of NDP and SOEF 1.1 but may not have capital approval.
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 x 10^9 joules 1 gigawatt hour = 1,000 megawatt hours 1 terawatt hour = 1,000 gigawatt hours
Minimum Sets (MUON)	There is a requirement to have a minimum number of conventional generators in Ireland and Northern Ireland.
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
Operational Limit for Inertia	There is a requirement to have a minimum level of inertia on the All-Island system.
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.
Reserve	The amount of spare capacity in the system to manage any system disturbance.
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 (TDD)	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).
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	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.

1. Introduction

The Enduring Connection Policy (ECP) governs how renewable generators and battery storage apply and get connected to Ireland’s electricity grid. Constraint Forecast Studies for ECP produce area reports on potential level of Dispatch Down that solar and wind generators may face. This can provide useful information about utilisation of renewable energy and the impact of network or operational developments to the existing generators, potential future generators, transmission system planners, regulators and the general public.

As ECP 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 managed on all-island basis.

This document describes the methodology used in producing Constraint Forecast Studies for ECP that results creation of the constraint forecast reports. For customers wishing to see assumptions or input data used, please see webpage[1].

The results 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 term “Total Dispatch Down” is used 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.

[1] ECP Constraint Reports | Customer Information | EirGrid

2 Study Overview

The evaluation of Total Dispatch Down is impacted by a range of assumptions: generation, demand, interconnection, network, and operational limits. Constraint forecasting generally selects three forecast years and a number of installed generation scenarios to provide a range of potential dispatch down scenarios in the future. Input assumptions for each of these can be found in the assumptions document on the constraints forecast for ECP website[2].

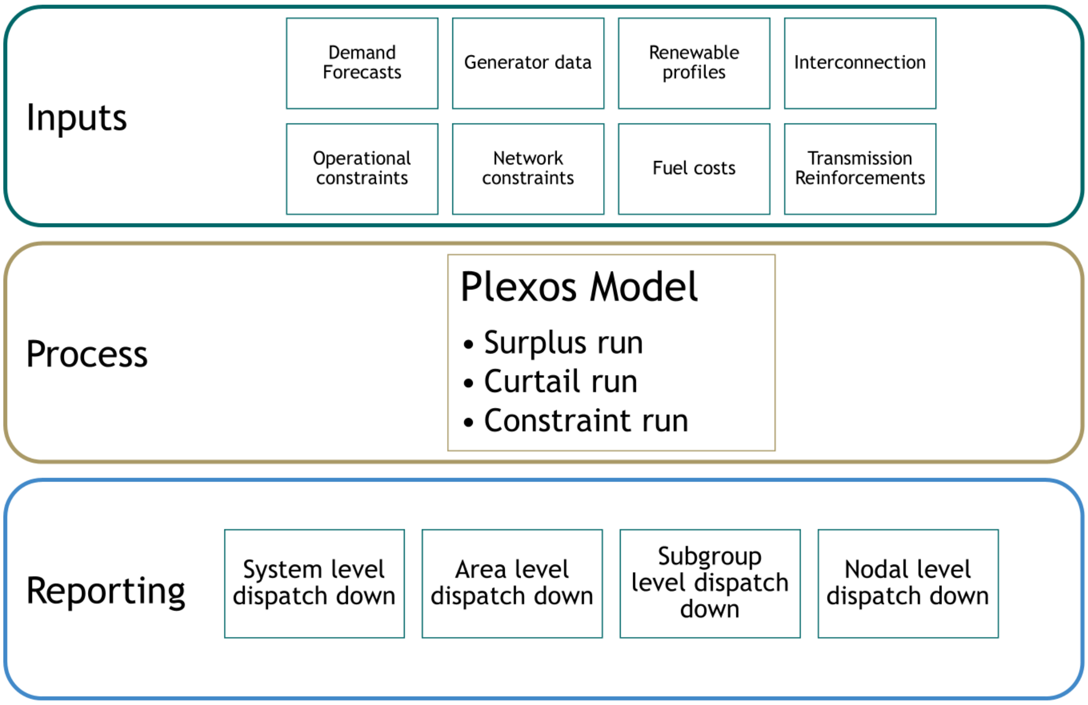

Figure 2-1: Overview of ECP constraints forecasting methodology

The data freeze for the generator and reinforcement input assumptions for this analysis is posted in the assumptions document. As a result, there may be some recent developments within the electricity network that may not be not included or have changed status since the data freeze date. However, all reasonable steps were taken to ensure that any significant updates to the assumptions were considered in the study.

The areas shown in Figure 2-2 are used for preparing wind energy profiles, for setting up generation scenarios and for reporting results. 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. During engagements with industry, they requested for further sensitivity studies and known as Future Grid scenario.

[2] ECP Constraint Reports | Customer Information | EirGrid

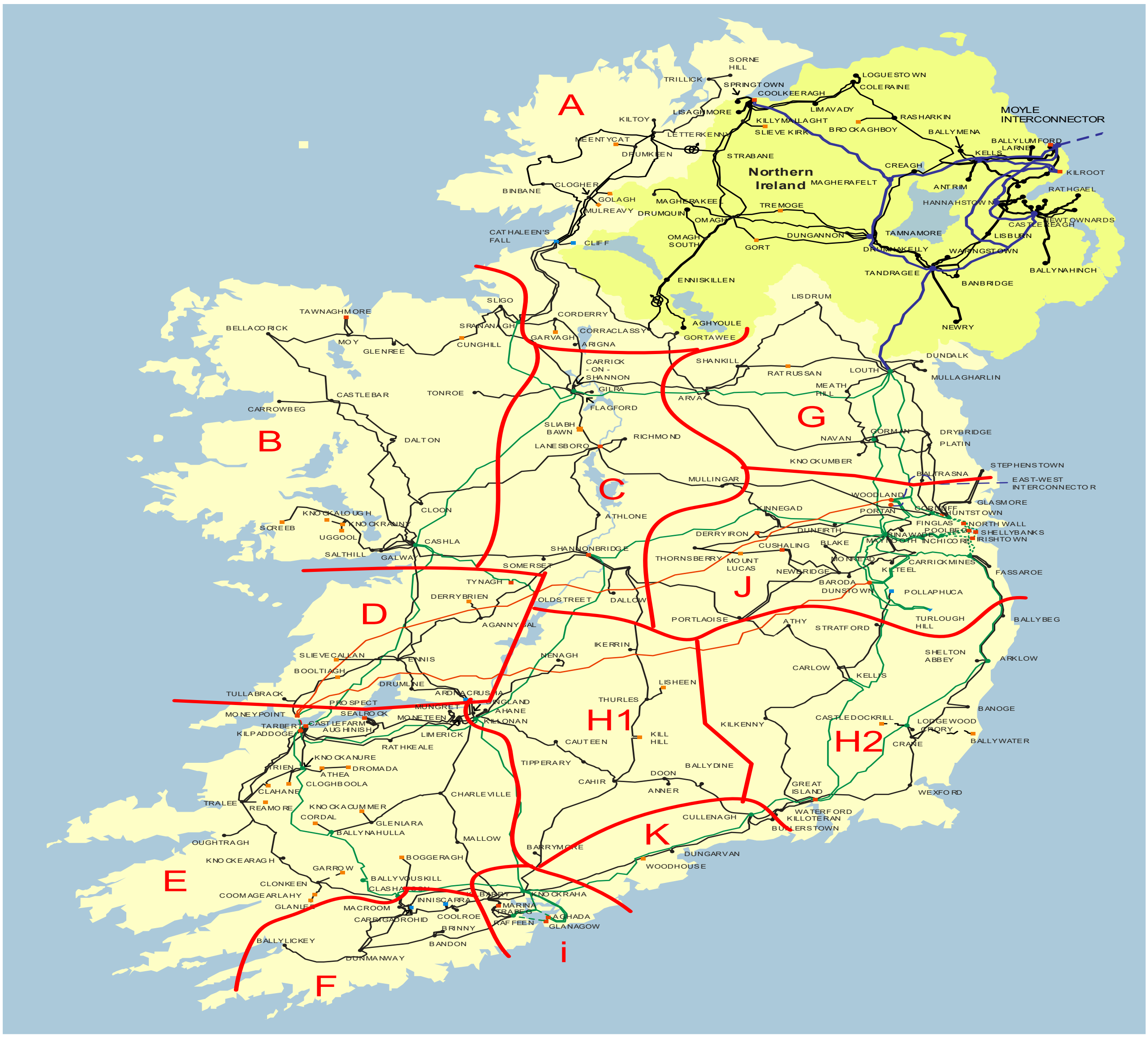

Figure 2-2 Areas Designated for Preparing Wind Energy Profiles, Generation Scenarios and Reporting Results

3 Modelling Methodology

3.1 Modelling Software

The tool used in ECP Constraints Forecasting is a production cost modelling tool called PLEXOS. 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. PLEXOS is a complex and powerful tool for power system analysis, with separate unit commitment and dispatch algorithms.

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 may require (depending on type of analysis):

- 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.
- Additional regional and zonal settings

3.2 Modelling Process

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.

For each studied scenario, three PLEXOS models are run sequentially. A simplified flow chart of the modelling process for each scenario is shown in Figure 3-1. The inputs for each model run will be discussed at a high level here and outlined in detail in the Modelling Inputs section.

The first model run is the surplus study which is an unconstrained run. Inputs to this model run are installed generation, renewable generation profiles, generator attributes, interconnection and demand. PLEXOS produces a generation dispatch for each hour across the forecast horizon. Within this run PLEXOS dispatches down generators which are the surplus dispatch down quantity. A post processing step is applied to re-distribute the dispatch down according to market rules subject to priority and non-priority status. The wind and solar profiles are updated to account for the forecast dispatch down and the updated profiles are used as the input to the next model run which is the curtailment run.

For the curtailment run, operational constraints are applied and the same process as above is repeated to forecast curtailment dispatch down. Following the post processing step the wind and solar input for the constraint study is prepared.

For the constraint study, network constraints are applied to the model, and the model is run to forecast constraint dispatch down for the wind and solar forecast generation for each modelled scenario. The constraint dispatch down is redistributed according to market rules via a pro-rata methodology or using 'grandfathering' of constraints.

From the above methodology we can calculate surplus, curtailment and constraint dispatch down which combine to give total dispatch down for the study. This process is repeated for all modelled scenarios.

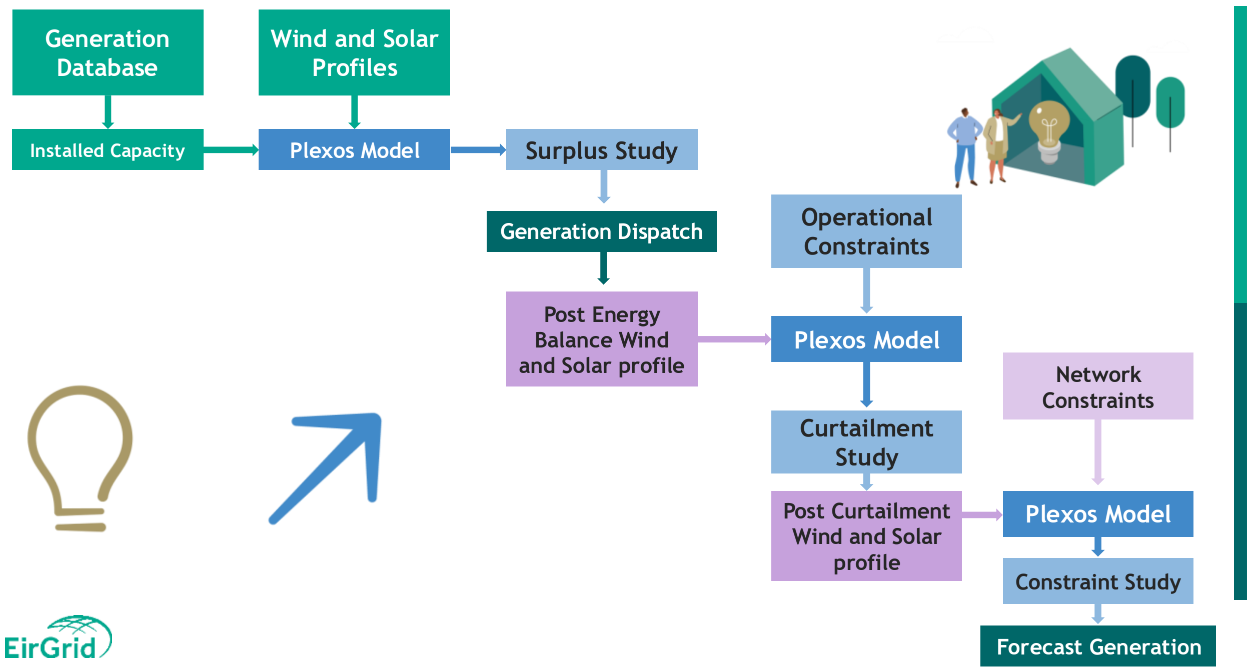

Figure 3-1 - Model methodology sequencing

4 Modelling inputs

4.1 Demand

The demand forecasts for Ireland and Northern Ireland are based on the latest All-Island Resource Adequacy Assessment (AIRAA) medium demand projections as published on the AIRAA section of the EirGrid website[3]. An hourly timeseries is created for each forecast year using the medium demand projection and demand profile from a representative weather year.

For more information on how demand is forecast, see the demand section of the latest AIRAA methodology report.

The demand forecast is inclusive of fixed loads. Additional post processing steps are required to attribute the fixed load to specific nodes in the model. The fixed loads are separated from the variable load for each hour such that the total demand per year will stay the same as per the AIRAA medium demand forecast.

Embedded solar is also accounted for in the demand forecast as outlined in Section 4.4.1.2.

The demand at each node in PLEXOS has been allocated as per Load Participation Factor (LPF). LPF is calculated based on the Summer Valley and Winter Peak nodal demand data published in Ten Year Transmission Forecast Statement (TYTFS).

Each node in the PLEXOS model is matched with a node in the forecast statement. A LPF is calculated for each PLEXOS nodes by dividing the load at that node in the TYTFS with the total sum of the load in the TYTFS scenario. The LPF for each node is then multiplied by the demand forecast time series to give the demand at that node for each hour.

Example:

$$Load\ at\ node\ A\ in\ TYTFS\ Winter\ Peak\ Scenario:\ 600\ MW$$

$$Total\ sum\ of\ load\ in\ TYTFS\ Winter\ Peak\ Scenario: 10{,}000\ MW$$

$$Node\ A\ LPF = \frac{600\ MW}{10{,}000\ MW} = 0.06$$

$$Demand\ forecast\ for\ Timeslot\ 1 = 11{,}000\ MW$$

$$Demand\ forecast\ for\ Node\ A, Timeslot\ 1\ =\ Demand\ forecast\ for\ Timeslot\ 1 * Node\ A\ LPF$$

$$Demand\ forecast\ for\ Node\ A, Timeslot\ 1\ =\ 11{,}000\ MW * 0.06 = 660\ MW$$

Where:

(i) "Load at Node A in TYTFS Winter Peak Scenario" is an example load at a specific example node in a TYTFS Winter Peak Scenario.

(ii) "Total sum of load in TYTFS Winter Peak Scenario" is the total load on the system in the example TYTFS Winter Peak Scenario during a specific timeslot.

(iii) "Node A LPF" is the load participation factor calculated for example node A.

(iv) "Demand forecast for Timeslot 1" is the expected total load on the system based on current demand data for example timeslot 1.

(v) "Demand forecast for Node A, Timeslot 1" is the expected load to be placed on example Node A based on current demand data for example timeslot 1.

The demand share at each node is not constant for all points in time. To improve the accuracy of the demand forecast, two sets of LPFs are calculated for each node, a Day LPF based on the winter peak demand, and a Night LPF, based on the summer peak demand. Using the two LPFs changes the distribution of the load

[3] All-Island Resource Adequacy Assessment

between day-time and night-time. While LPFs are likely to vary over the different model horizons, forecasting this variance is beyond the scope of ECP constraints forecasting and the same LPFs are applied to each forecast year.

4.2 Installed Capacity

Most of the installed generation capacity in the constraints forecast for ECP can be classified as renewable generation, storage or thermal generation. The thermal generation included in the model is based off the latest AIRAA portfolio for each forecast year. To see details of the thermal generation included in the model, see the assumptions document or the data workbook published on the AIRAA section of the EirGrid website.

For renewable generation and storage installed a variety of generation scenarios are included to take account of different levels of generation connection or 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.

These portfolios consider all projects entering through all ECP pipelines to date as well as previous Gate and Pre-Gate applications, ORESS auctions and SOEF. Projects that were successful in previous application process or auctions but lapse are not included in the generation portfolios. The generation portfolios are correct as of the data freeze date. If a project lapses post the data freeze date this may not be reflected in the auction but will be included in the next constraint forecast iteration.

Generally, three core generation scenarios are included; Initial, 50% and ECP. 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. for study year 2028, the Initial 2028 Scenario includes all renewable generation up to and including the latest ECP pipeline applications expected to connect by 31st Dec 2027 (Baseline).

The "ECP" (full) scenario includes all renewable generation up to and including the latest ECP pipeline applications for the given study year.

The "50%" scenario is the mid-point between the Initial scenario and the ECP scenario. It is created by subtracting the installed capacity in the Initial scenario from the ECP scenario and scaling the result down by 50% and adding it back onto the Initial scenario's installed capacity. In this portfolio, all capacity included in the ECP portfolio but not included in the Initial portfolio is scaled by 50%. Under the current constraints forecasting for ECP, all renewable units are scaled equally, and no differentiation is made for forecast connection date.

Example:

In the Initial scenario there is 1000 MW of installed wind non-priority connected to a node. In the ECP (full) scenario there is 1800 MW Of installed wind non-priority connected to that node.

Installed wind non-priority connected capacity connected to that node in the 50% scenario:

$$\frac{[1800\ MW\ (ECP) - 1000\ MW\ (Initial)]}{2} + 1000\ MW\ (Initial) = 1400\ MW(50\%)$$

Where:

(i) "MW (ECP)" is the installed capacity in the "ECP" (full) scenario.

(ii) "MW (Initial)" is the installed capacity in the initial scenario.

(iii) "MW (50%) is the installed capacity in the 50% scenario.

Additional installed generation scenarios may be included as sensitivities. The levels of installed thermal generation, storage, solar, wind, and offshore wind generation as well as interconnection included in each scenario are included in the assumptions document.

4.3 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. Fuel costs.
6. Startup cost and startup time

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 emission restrictions.

Fuel costs are applied to all thermal generators in the PLEXOS model and are an input in deciding the cost of running a unit. The fuel costs in the model vary with the model horizon. The fuel cost projections in the model are sourced from National Grid's Future Energy Scenarios[4]

The carbon price has derived from the same source, with EU ETS carbon price (EUR/tonne) has been taken as a reference.

4.4 Renewable Generation

The level of installed renewable capacity is a key input to the constraint forecast studies for ECP as the level available renewable energy has a significant impact on dispatch down. The methodology for deciding our generation portfolios is included in section 4.2.

The generation from a renewable generator depends primarily on the availability of wind and solar resources. To measure the actual energy output over time, we often use the capacity factor, which represents the ratio of the energy produced by a generator to the maximum possible energy it could produce if it operated at full capacity for an entire year. To forecast renewable generation, we utilize profiles for renewable units using historical data. More information on how the wind and solar profiles are constructed is included in the sections below. Additionally, the wind year or the historical weather year used to calculate the profiles is included in the assumptions document.

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.

[4] FES: Data Workbook 2025

4.4.1.1 Solar Modelling

The energy available to a solar generator depends on a number of factors including location, cloud cover, time of day and time of year.

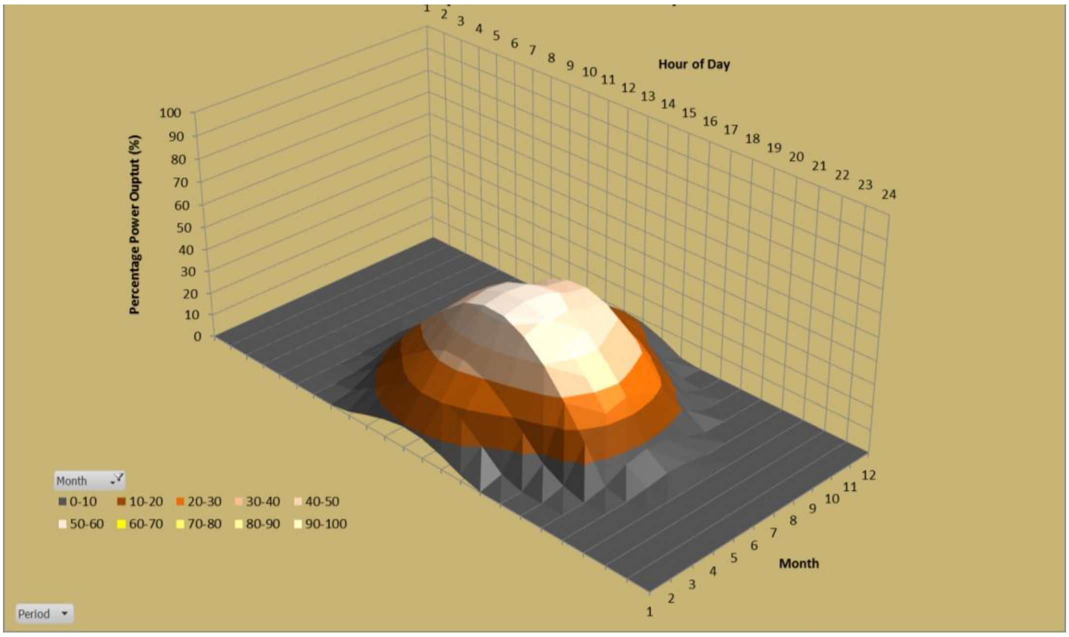

Figure 4-1 Representative Solar Energy Profile (Monthly Average - Hour of Day)

To capture the factors influencing solar generation, we use hourly solar profiles based on historical data. If necessary solar data is not available for a region for the study year, a forecasted profile is used.

The solar profiles were used in a grouping approach: solar north, solar middle, and solar south. The weather year used to create these profiles are available in the assumptions document. 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.

To calculate the generation of a solar unit for any timeslot in the year, the capacity of the generator just needs to be multiplied by the capacity factor for that location and timeslot.

Example:

$$Capacity\ of\ Solar\ Generator\ A: 100\ MW$$

$Location\ of\ Solar\ Generator\ A: Solar\ Middle$

$$Capacity\ factor\ for\ Solar\ Middle, Timeslot\ 1\ (Month\ 1, Day\ 20, Hour\ 14)\ =\ 0.20$$

$$Generation\ of\ Solar\ Unit\ A, Timeslot\ 1\ =\ 100\ MW\ *\ 0.20\ =\ 20\ MW$$

Where:

(i) "Capacity of Solar Generator A" is the manufacturer rated capacity of example solar generator A.

(ii) "Location of Solar Generator A" is the capacity factor grouping assigned to Generator A based on location as per Figure 4-2 Example Capacity Factors of Groupings Used for Solar Profiles in the Mode.

(iii) "Capacity factor for Solar Middle, Timeslot 1" is the capacity factor used for generators within the Solar Middle location grouping during the specific example timeslot 1.

(iv) "Generation of Solar Unit A, Timeslot 1" is the expected output of example generator A during timeslot 1.

The groupings used and example averaged capacity factors of the different profiles are shown in Figure 4-2.

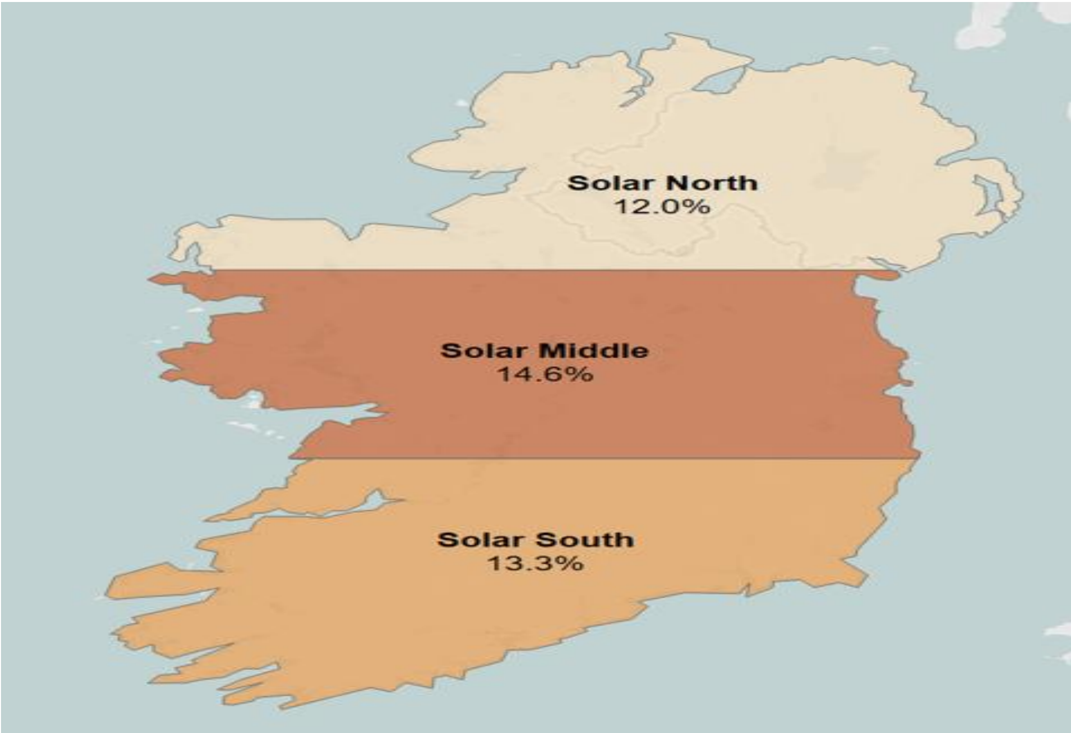

Figure 4-2 Example Capacity Factors of Groupings Used for Solar Profiles in the Model

4.4.1.2 Embedded Solar

Embedded Solar installed capacity inputs for Ireland have been provided by ESB Networks and those projections are based on NC6, NC7 and NC8 contracts*. For Northern Ireland, SONI provides forecast installed embedded solar levels.

To create an hourly generation profile for embedded solar, an average profile is calculated from the three utility solar profiles used in the model. To account for efficiency differences between utility scale solar and embedded solar, an annual capacity factor of 10% has been assumed for embedded solar. The hourly profile is applied to the installed capacity figure for embedded solar to create an hourly generation profile.

The total embedded solar capacity is netted off the hourly demand profile used in the model. Embedded solar is assumed to be proportional to demand at each node.

**Note: NC6, NC7 and NC8 are application forms for connecting small-scale RES (micro/mini-generation), typically solar, to the electricity grid of Ireland, managed by ESB Networks. NC6 is for smaller (<6kW), NC7 for medium-sized (from 6 up to 50kW) and NC8 for larger systems (from 50 up to 200kW).*

4.4.2 Wind Profiles

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 for each area 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. The weather year used to create these profiles are available in the assumptions document.

By using historical wind profiles, it is possible to account for the geographical variation of wind power across the island. The offshore wind profiles have been procured from an external vendor. The weather year used to create these profiles are available in the assumptions document.

To calculate the generation of any wind unit for any timeslot in the year, the capacity of the generator just needs to be multiplied by the capacity factor for that location and timeslot, using the same methodology as the solar units use.

Example capacity factors of 2020 wind profiles are shown in Figure 4-3.

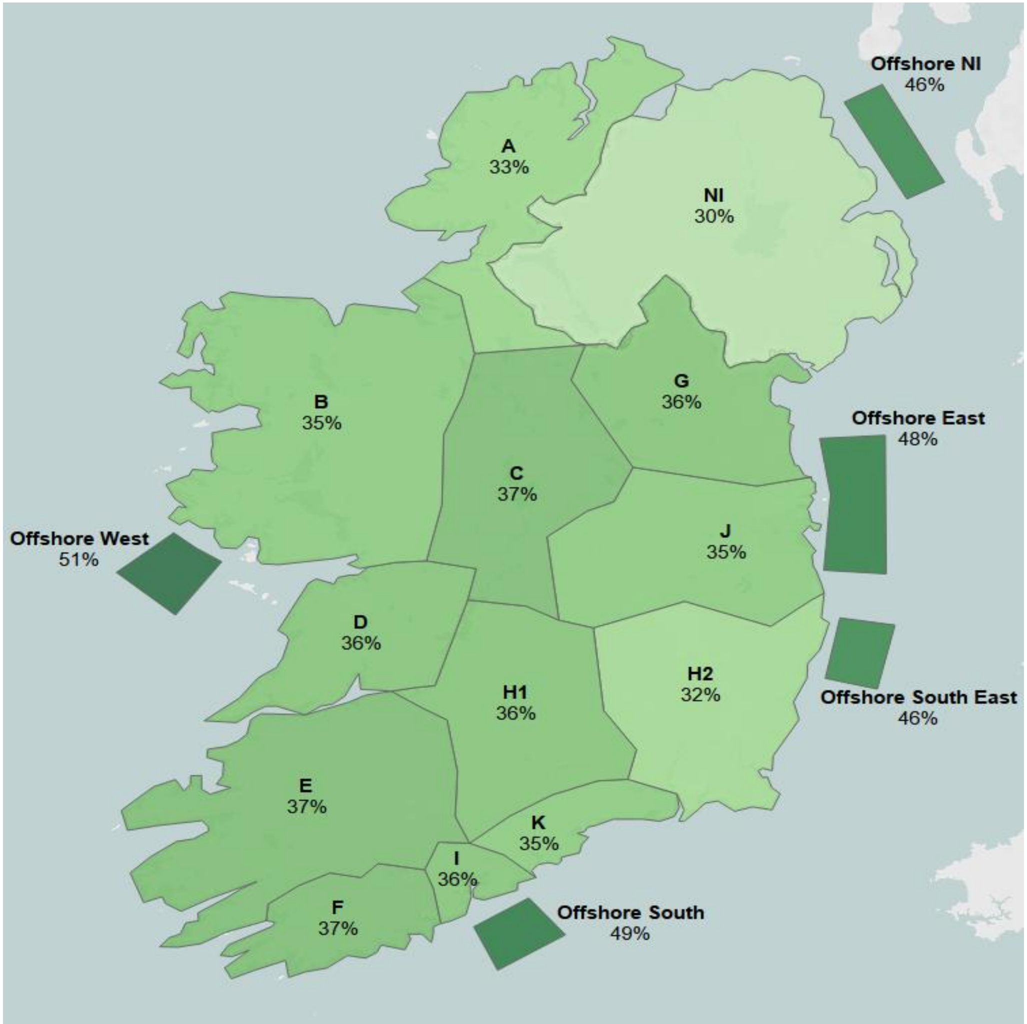

Figure 4-3 Example Capacity Factors by Area for Wind

4.5 BESS (Battery Energy Storage System)

The methodology for inputting the installed battery capacity is discussed in Section 4.2 and the quantities can be found in the assumptions document. For this analysis batteries have been modelled using the battery class within PLEXOS. They have been modelled using the general assumptions shown below.

Example 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 4-1: 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.

The current methodology does not differentiate between short duration and longer duration batteries regarding the assumptions outlined in Table 4-1. Batteries are assumed to be 100% available and PLEXOS optimises their charging and discharging separately in each model run. The batteries are optimised in surplus, curtailment and constraint runs independently of the previous run. As a result, a single battery may have a different load profile in each of the surplus, curtailment and constraint runs for a single scenario.

4.5.1 BESS modelling

The shorter duration batteries (batteries with a storage duration of <= 1 hours) are used 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 the assumptions document on the ECP website.

The longer duration batteries (batteries with a storage duration of > 1 hours) are used both to provide energy arbitrage, and to contribute to replacement reserve requirement. The cycling of these batteries is decided by the PLEXOS optimisation to minimise total system costs.

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. More information on reserve requirements can be found in Section 4.7.5.

4.6 Interconnector

The purpose of the constraint forecast report is to model and predict estimated levels of dispatch down, both at a system level, and on a regional (Area) level. To accomplish this forecast, the model requires various inputs, one of which is the Interconnector flow model. This section details the methodology by which the interconnector model was created.

The SEM is modelled as a full network representation of all transmission nodes within the SEM. In order to appropriately model the interconnector flows between the SEM, Great Britain (GB), and France – one node is added for GB and one node is added for France. The interconnectors are then connected between their nodes with connections between GB and the SEM, France and the SEM (when Celtic commissions) and between France and GB.

The purpose of creating two new nodes for GB and France is to create a simplified dispatch for GB and France which is able to approximate available resources and their cost in GB and France. This dispatch schedules interconnector flows based on minimising cost and ensuring the region with the cheapest generation exports to a region with more expensive generation. This produces a dynamic price model where the price fluctuates from hour to hour for GB and France.

4.6.1 GB and France inputs

In order to create this simplified dispatch model for GB and France, this modelling relies on key inputs from the latest European Network of Transmission System Operators for Electricity (ENTSO-E) European Resource Adequacy Assessment (ERAA).

Demand for each forecast year for both France and GB is created using a representative weather scenario from ERAA the latest ERAA model.

Installed renewable capacity forecasts for each forecast year for both France and GB are created using the latest ERAA forecast data for each region. Installed renewable capacity in each region is divided into different categories: Solar PV, Onshore Wind, and Offshore Wind.

Renewable profiles are based on the latest available ERAA data and are applied to each region and technology category to forecast available energy.

To simplify the modelling, all non-renewable generation for GB and France is approximated with a single thermal unit in each node. The main properties of this unit are different price points depending on the amount of thermal capacity required. This is following the principle of a simple merit order whereby if a lower amount of capacity is required, a lower cost unit would be dispatched, and therefore, a lower price point will supply the energy. The price points of this thermal unit have been calibrated based on recent historical day-ahead prices from GB.

Changing fuel costs over time is obtained from National Grid's latest Future Energy Scenarios forecast.

4.6.2 Interconnector Flow Modelling

During the surplus run, the model optimises the interconnector flows based on the supply-demand balance and the capacity limits of the interconnectors for the SEM, France, and GB regions. As the model optimises for total cost in the model, the optimised interconnector flow will generally be from the less expensive region to the more expensive region. The model then computes a marginal price for each region which can be useful for understanding the directionality of the interconnector flows.

An illustrative day can be seen in Figure 4-4, where the marginal price in the SEM and GB can be seen – with the prices computed in the same dispatch. Periods of exports from the SEM occur when the SEM price is lower than the GB price, and imports to the SEM occur when the SEM price is higher than the GB price.

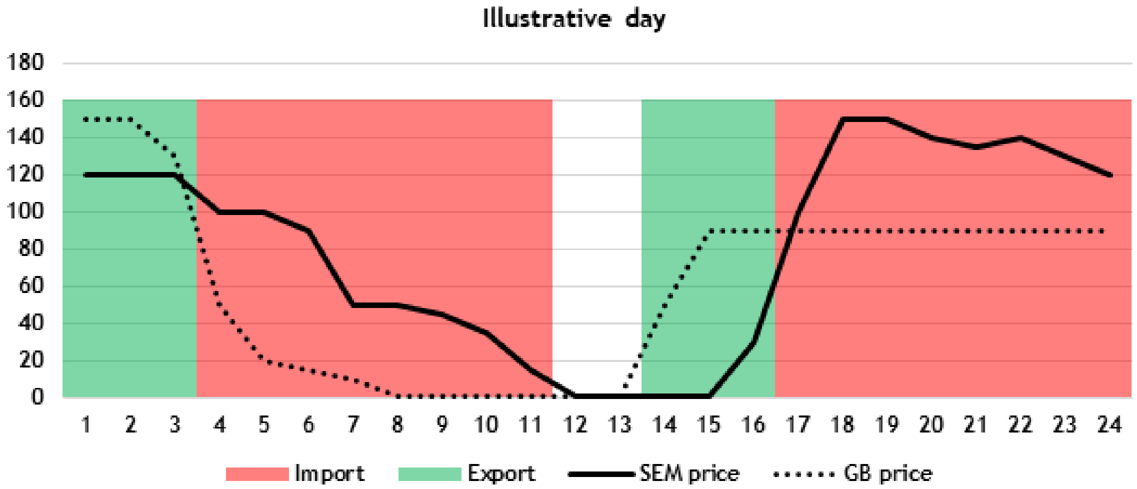

Figure 4-4: Illustrative day for interconnector dispatch using the new interconnector methodology

For each forecast scenario and sensitivity, the interconnector flows are fixed after the surplus stage and the same interconnector flows apply to the curtailment and constraint model runs.

4.7 Operational Constraints

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 for which it 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.

4.7.1 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 4-2. These operational constraints have been taken from the Operational Policy Roadmap 2025 – 2035[5] and are aligned to the SOEF 1.1 Roadmap and weekly operational constraints[6] where applicable. The RoCoF limit was not monitored in the PLEXOS study but is included in Table 4-2 for information purposes.

Active System Wide Constraints	
System Non-Synchronous Penetration (SNSP)	There is a requirement to limit the instantaneous penetration of asynchronous generation connected to the All-Island system.
Operational Limit for Rate of Change of Frequency (RoCoF)	There is a requirement to limit the RoCoF on the All-Island system.
Operational Limit for Inertia	There is a requirement to have a minimum level of inertia on the All-Island system.
Minimum Sets **(IE, NI)**	There is a requirement to have a minimum number of conventional generators in Ireland and Northern Ireland.
Reserve **(IE, NI)**	The amount of spare capacity in the system to manage any system disturbance.

Table 4-2 Active System Wide Operational Constraints (SNSP, Inertia & Minimum Sets)

[5] Operational Policy Roadmap 2025-2035 | Soni

[6] Wk48_2025_Weekly_Operational_Constraints_Update.pdf

4.7.2 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:

$$\frac{All\ Island\ non-synchronous\ Generation + BESS\ Discharges + Interconnector\ Imports}{All\ Island\ Demand + BESS\ Charges + Interconnector\ Exports} \leq SNSP\ Limit^{7}$$

Where:

(i) "All Island non-synchronous Generation" is total available generation from non-synchronous sources in both IE and NI.

(ii) "BESS Discharges" is total output of discharging battery energy storage systems.

(iii) "Interconnector Imports" is the total energy flowing into IE and NI through interconnectors.

(iv) "All Island Demand" is the total combined electricity demand for IE and NI.

(v) "BESS Charges" is the total electricity demand created by charging battery storage systems.

(vi) "Interconnector Exports" is the total energy flowing out from IE and NI through interconnectors.

(vii) "SNSP Limit" is the System Non-Synchronous Penetration Limit.

An increase in the SNSP limit will allow more 'non-synchronous' generation to be accepted onto the system, which includes all wind and solar generations.

4.7.3 Inertia

There is a requirement to have a minimum number of inertia providing units operating at all times. These units are split between IE and NI. The goal of these units is 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.

4.7.4 Minimum Sets (MUON)

Some units are placed in groups referred to as minimum sets and there is a requirement for a minimum number of these units to be operating at any one time (MUON). More information on this requirement can be found in the Assumptions Document or the weekly operational constraints reports.

4.7.5 Operating Reserve

Operating reserve is additional 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 and other storage types, interconnectors, and demand response, in the future, it is expected that a greater share of reserve may be maintained by such non-conventional sources.

Conventional generators such as gas, distillate can provide replacement reserve for IE and NI. Batteries can also contribute to operating reserve as described in Section 4.5 section of this report.

Before the Celtic interconnector was commissioned, the minimum reserve requirement was 500MW based on the Largest Single Infeed (LSI) which is the EWIC interconnector. After the commissioning of the Celtic interconnector, the reserve requirement was increased to 700MW in line with its rating. In both cases, the

[7] SNSP Calculation Update V1.0_SEMO.pdf

split in the reserve between IE and NI has been made in the ratio of 75/25. The operating reserve requirements modelled in the analysis can be seen in Table 4-3.

Operating Reserve Requirement		
Reserve	**Minimum Requirement (MW)**	**Provided by**
SEM POR/SOR/TOR*	500 (700)	<= 1hr BESS
IE Replacement Reserve	375 (525)	> 1hr IE BESS + IE Thermal
NI Replacement Reserve	125 (175)	> 1hr NI BESS + NI Thermal
*Combines POR, SOR, TOR I and TOR II		

Table 4-3 Example Operating Reserve Requirements for each model

4.8 Network

4.8.1 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 2025 can be seen in Figure 4-5. In addition to the current transmission network a number of network reinforcements are considered in each network scenario (see examples in Figure 4-6). A list of the network reinforcements used in the study is provided in the assumptions document on the ECP webpage.

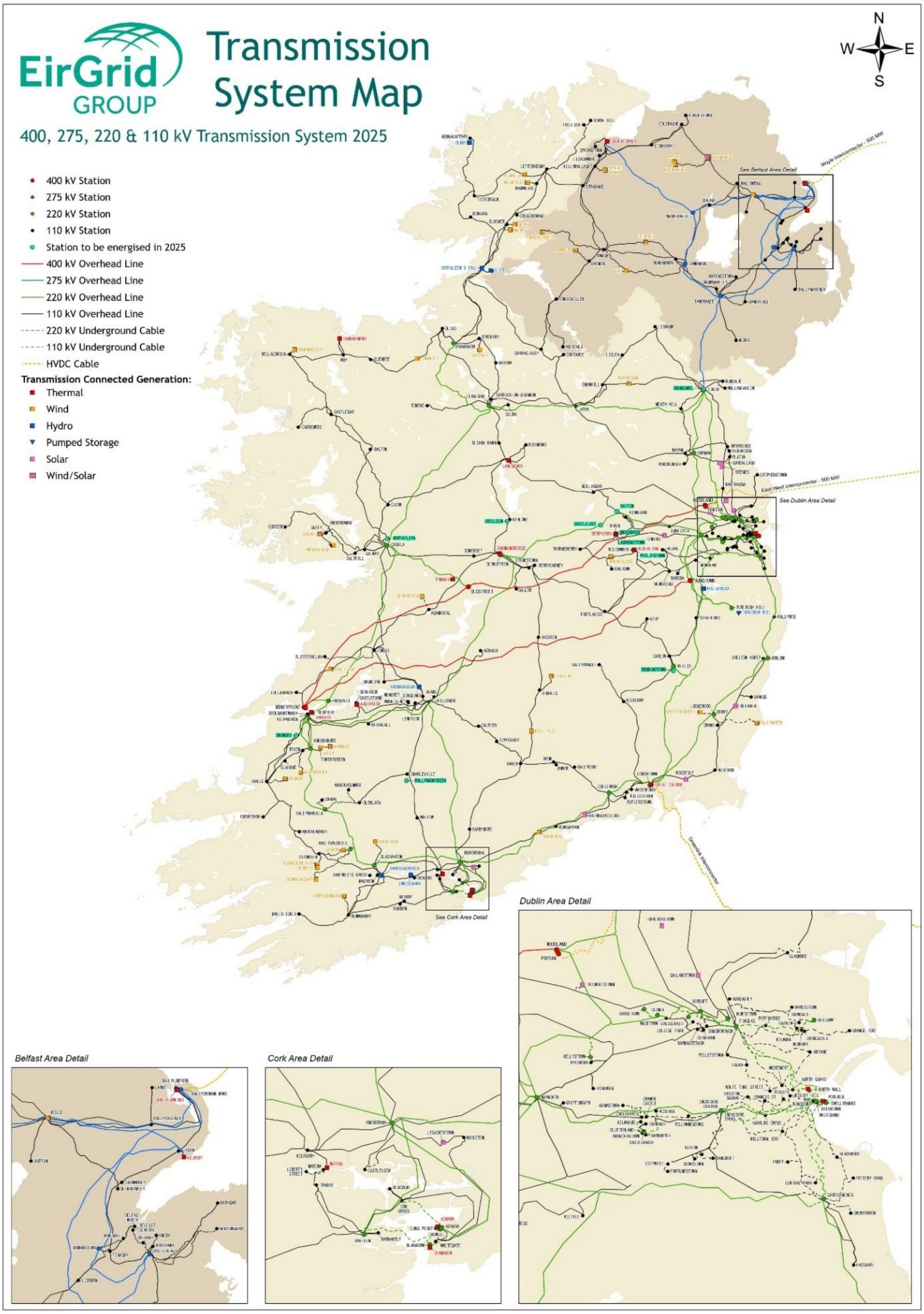

Figure 4-5 Ireland Transmission Network 2025

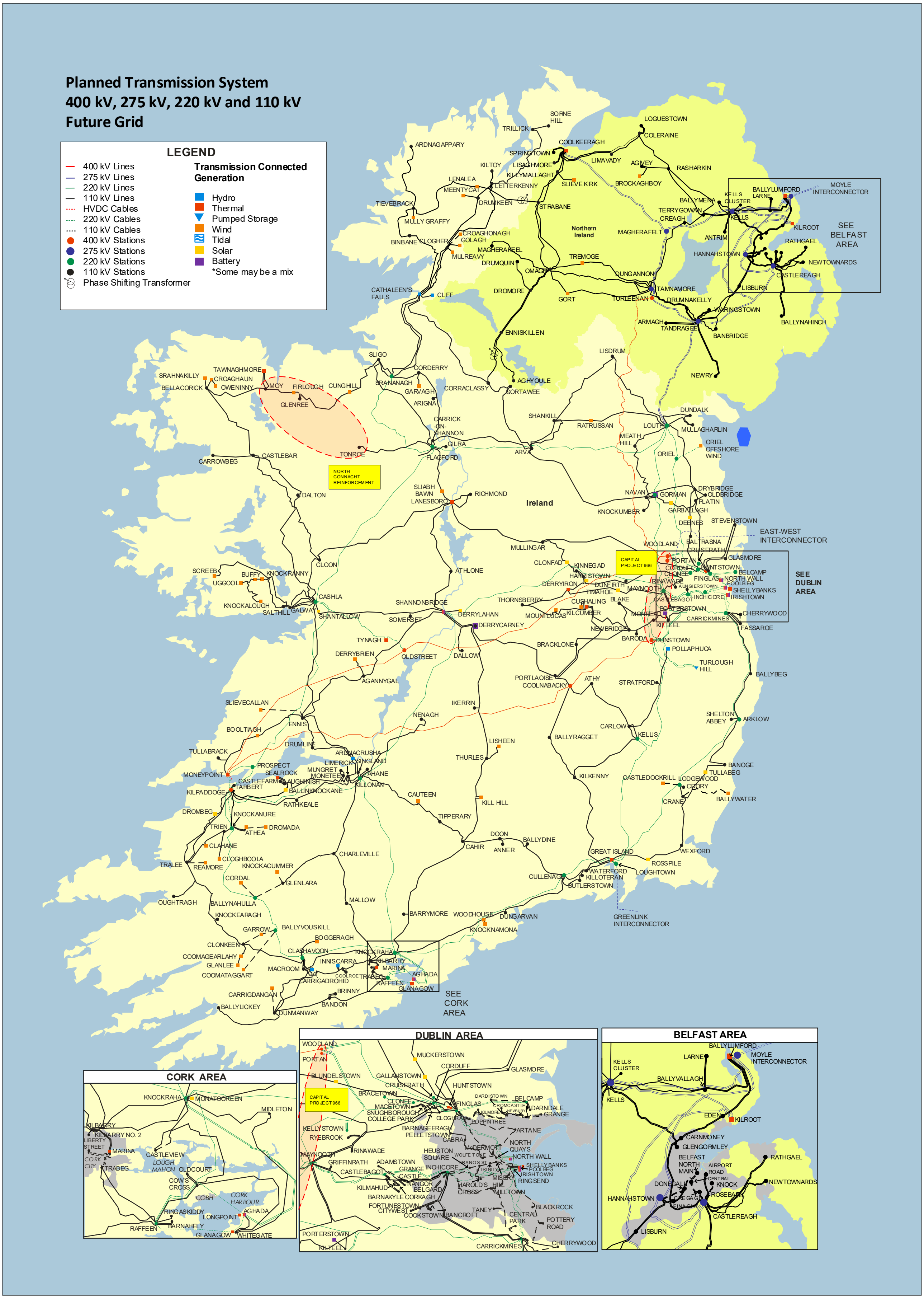

Figure 4-6   Ireland Transmission Network Showing Assumed Future Network Reinforcements and Stations

4.8.2 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.

4.8.3 Ratings and Overload Ratings

The rating of each circuit in the model is determined by the circuit limiting element, i.e. the element of the circuit with the lowest thermal rating decides the rating for the whole circuit. Generally, a seasonal rating applied to each circuit where each circuit has a summer rating, a winter rating and a spring / autumn rating.

Where applicable, an overload rating is applied to the circuit, allowing the line to overload its rated capacity by as much as 10% for a limited time period.

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 constraints analysis include N-1 contingency monitoring and both ratings and overload ratings.

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. DLR is modelled with respect to the wind availability within the area that the DLR will be installed. DLR is modelled dynamically meaning a new rating is calculated for the circuit for each timeslot in the forecast horizon.

DLR can increase a line rating by up to a maximum of 30%. This 30% figure will be reviewed if more data becomes available but took a conservative view of initial DLR improvement assumptions of 30-45%. The amount that DLR can increase a line rating by id dependent on the wind capacity factor, the seasonal rating of the circuit element where DLR is installed, and the rating of the lowest rated element of the circuit that isn't affected by the installation of DLR.

The formula for calculating the circuit rating with DLR for any timeslot is:

$$Circuit\ Rating = MIN\left(CLE_{non-DLR}, \quad 0.3 * CF_{Wind} * Rating_{pre-DLR}\right)$$

Where:

(i) Circuit Rating is the rating of the entire circuit post installation of DLR for a specific timeslot in the model horizon.

(ii) $CLE_{non-DLR}$ is the rating of the lowest rated element on the circuit that isn't affected by the installation of DLR.

(iii) CF_{Wind} is the wind capacity factor applied to the area that the DLR is installed at the specified timeslot in the model horizon.

(iv) $Rating_{pre-DLR}$ is the seasonal rating of the element of the circuit where DLR is being installed, pre DLR installation.

Example:

DLR is installed on a line in Area A where the overhead line is the circuit limiting element with a rated capacity of 200 MW pre-DLR install. The next limiting element on the circuit is rated 270 MW. Wind Capacity Factor in Area A at Timeslot 1 is 0.9.

$CLE_{non-DLR} = 270\ MW$

$CF_{Wind} = 0.9$

$Rating_{pre-DLR} = 200$

$$Circuit\ Ratingm\ at\ timeslot\ 1 = MIN(270\ MW, \quad 0.3 * 0.9 * 200\ MW)$$

$$Circuit\ Ratingm\ at\ timeslot\ 1 = MIN\ (270\ MW, 254\ MW) = 254\ MW$$

4.8.4 Transmission Reinforcements

For each study year 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.

A full list of the transmission reinforcements (new build, uprates and DLR's) assumed in the constraints modelling is included in the assumptions document.

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[8].

4.8.5 Transmission Network Outage Programme

The model includes a representative transmission outage schedule. The outages within this schedule represent a geographical spread of circuits across the system and were each configured for a one-month period. This allows a representation of outage impact in each geographical area to be included within the studies.

An outage to any circuit will decrease the net transfer capacity of the entire network and is likely to increase the forecast levels of dispatch down. A number of one-month outages spanning the whole year are selected as a representative schedule. The transmission outage plan in the model is generally applied so that there is only one outage in a given area at any time and the same outage plan is applied to each forecast year. This schedule was created by working alongside the transmission outage planning team and by analysing historical transmission outage plans. The transmission outage schedule used in this analysis is included in the assumptions document.

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

5 Reporting

In constraints forecasting for ECP, we generate forecasts of total dispatch-down in Ireland under each scenario. These forecasts are further broken down into surplus, curtailment, and constraint, and analysed across several dimensions:

- Priority vs. non-priority generators
- Wind vs. solar generation
- Regional variations within Ireland

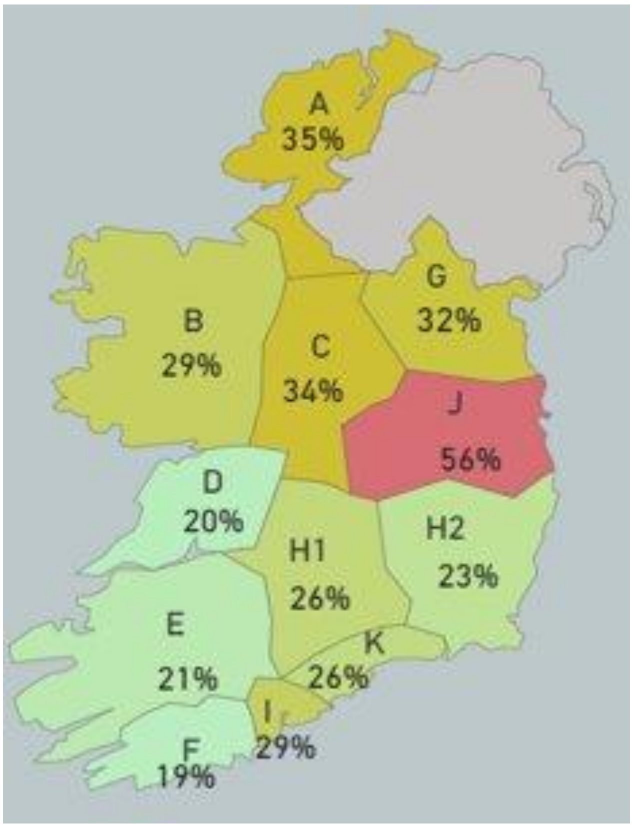

Figure 5-1: Example of areas included in an ECP constraints forecast. This image is for illustration purposes only and is not representative of forecast dispatch down.

We present these results to stakeholders in a number of ways:

- A webinar presenting draft results.
- An Ireland Summary of Results report with area level results on a high-level basis posted to the ECP constraints forecast website[9].
- Area level reports including results including overviews of dispatch down, installed capacity assumptions and network assumptions.

[9] ECP Constraint Reports | Customer Information | EirGrid

5.1 Interpreting the report

The ECP constraints forecast can be analysed at four levels: system, area, subgroup, and substation.

1. **System Level**

At the system level, we consider the entire IE jurisdiction of the **Single Electricity Market (SEM)**, which includes all generators and substations in Ireland (note: while the entire SEM including IE and NI are modelled in constraints forecasting for ECP, only IE is reported on). Results at this level are presented using several bar charts:

- Installed capacity: the installed capacity bar graph represents the gigawatts (GW) capacity of all installed renewable generation in the SEM for each completed study. It is broken down by technology type including priority wind, non-priority wind and solar, and uncontrolled wind and solar. The height of any of these categories on the bar chart represents the installed GW of that technology and the total height of the bar chart represents the total height of RES in that study. As installed capacity is kept constant for the same portfolio in different study years, we would expect the installed capacity for 2028 ECP to equal the installed capacity for 2030 ECP and the installed capacity for any ECP study to be bigger than the installed capacity for any 50% study which is bigger than the installed capacity for any initial study.
- Energy TWh: the energy TWh bar graph represents the total renewable energy available in the SEM for each study. It is broken down to show how much of the available energy is used for generation and how much is dispatched down as surplus, curtailment and constraint. Available energy depends on installed capacity, so larger portfolios yield higher available energy. Weather data is consistent across forecast years, meaning the same scenario in different years should have the same available energy. However, the share used for generation versus dispatch down will vary based on demand, interconnector flows, and network constraints.
- Total dispatch down (%): The total DD% graph represents the percentage of available energy dispatched down as surplus, curtailment and constraints in each study. Dispatch down generally increases with higher installed capacity. For the same installed capacity, dispatch down typically decreases in later forecast years due to higher demand and planned transmission reinforcements.

2. **Area Level**

The SEM is divided into geographic areas (see Figure 4). For each area, we provide the same metrics—installed capacity, available energy, and dispatch down—as at the system level.
Key considerations:

- Installed capacity varies by area and technology type.
- Weather conditions affect renewable energy availability by location.
- Dispatch down differs by area due to local network constraints.

Example:
In the 2028 and 2030 full ECP studies in ECP 2.5 constraint forecast studies, **Area A** and **Area J** have similar non-priority wind capacity. Surplus dispatch down for this technology is similar in both areas, suggesting weather differences have little impact. However, constraint-related dispatch down is much higher in Area J in 2028, indicating greater network congestion. By 2030, constraints in Area J decrease significantly, reflecting effective network upgrades. Including a 2035 study shows further reductions in Area A, confirming reinforcements there are scheduled later than 2030.

3. **Subgroup level**

Ireland's transmission system is a meshed network, meaning high flows on one line can overload another. When constraints occur, dispatch down is often applied to **subgroups** of generators that can relieve the issue.

- Subgroups differ from areas and can change as the network evolves.
- ECP reports often present results by subgroup, where generators of the same technology within a subgroup share the same dispatch down percentage.

Example:
The **Gortawee** generator is in Area A but belongs to subgroup **G North** because reducing its output impacts G North lines more than Area A lines. Consequently, non-priority wind at Gortawee experiences different constraint dispatch down compared to other non-priority wind in Area A.

4. **Substation level**

Finally, ECP constraints analysis can report results at the substation level, providing installed capacity, available energy, and dispatch down volume and percentage for each substation in the SEM.

5.2 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 4.2

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.

5.3 Apportioning of Surplus, Curtailment and Constraint

5.3.1 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.

5.3.2 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.

5.3.3 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.

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[10]. 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 constraint forecast studies, a set of sensitivity studies can also be included in the study scenarios which employs pro-rata allocation of constraints.

[10] SEM-22-009 Decision Paper on Dispatch, Redispatch and Compensation Pursuant to Regulation (EU) 2019/943 | The Single Electricity Market Committee

5.4 Calculations

To present the outcome of the ECP constraints analysis different levels of post processing calculations are executed on the availability and generation figures for renewable energy. This process is shown in the diagram below and the steps are expanded on the below tables. Please note that these steps are only applied to renewable energy / generation.

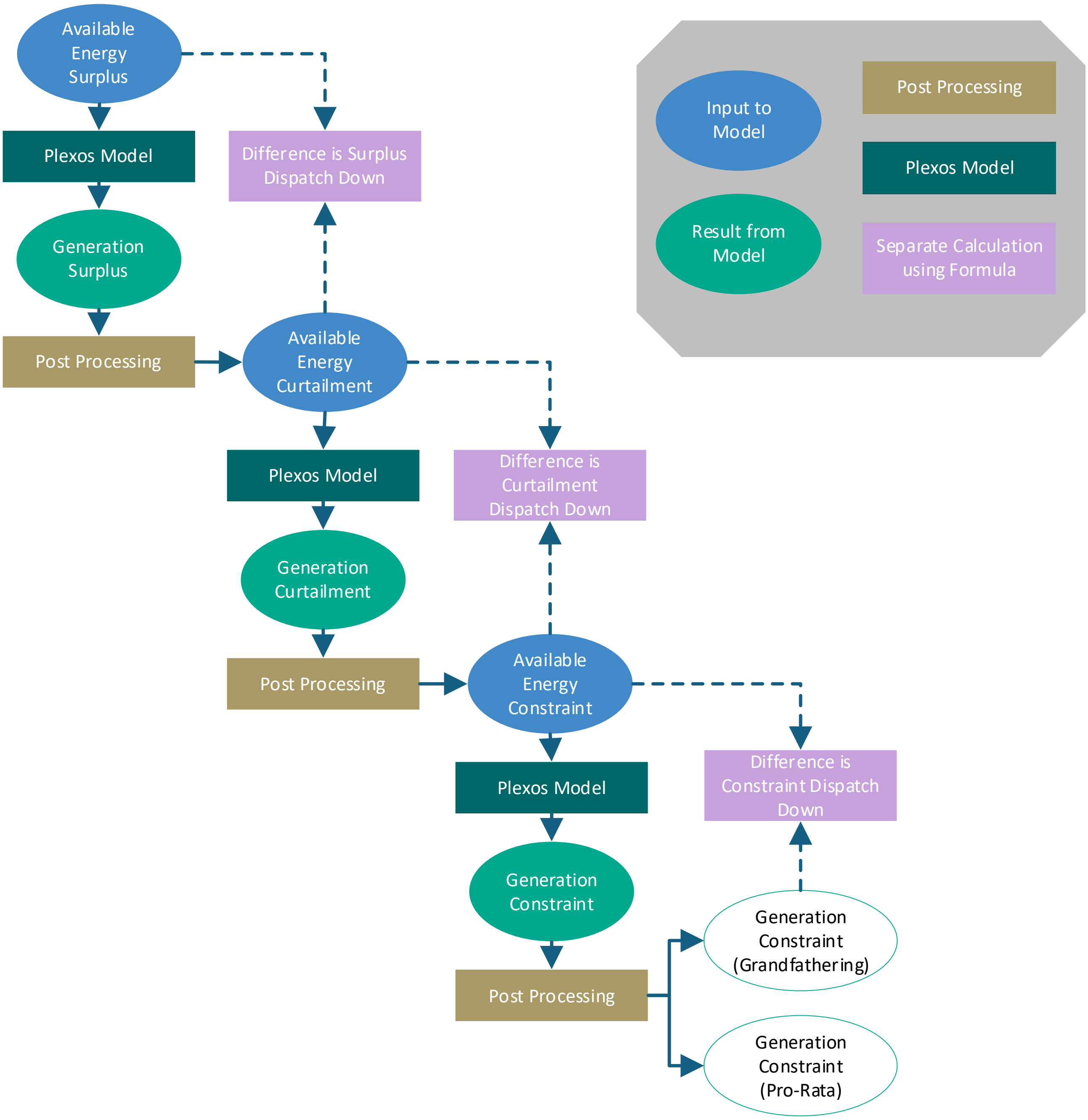

Figure 5-2: Process diagram of dispatch down calculations

Table 5-1: Surplus dispatch down calculation

Quantity	Description
Available Energy Surplus Study	Forecast **Available Energy** in the surplus study is a product of installed capacity and RES profiles. The available energy for any unit, node, subgroup, area or system can be extracted from the PLEXOS model
Generation Surplus	*Values extracted from PLEXOS Simulation Run* Forecast **Generation Surplus** is an output of the surplus study. It represents PLEXOS' dispatch of generators may not reflect the dispatch of generators according to market rules.
Generation Surplus Post Processing	This step is a result of post processing of the generation output of the surplus study*.
Surplus Dispatch Down	$\boldsymbol{Available\ Energy\ Surplus - Generation\ Surplus\ Post\ Processing}$ **Surplus Dispatch Down** can be calculated for any unit, node, subgroup, area or system can be extracted from the PLEXOS model
Surplus Dispatch Down (%)	$\frac{\boldsymbol{Surplus\ Dispatch\ Down}}{\boldsymbol{Available\ Energy\ Surplus}} \times 100$

*Please note that Surplus Dispatch Down is applied to non-priority generators ahead of priority generators. If the surplus is not resolved, priority generators are also dispatched down. While it is applied pro-rata within these categories, the availability of renewable energy is dependent on technology type and location, so Surplus Dispatch Down (%) will vary from area to area and based on technology type.

Table 5-2: Curtailment dispatch down calculation

Quantity	Description
Available Energy Curtailment	$\boldsymbol{Available\ Energy\ Curtailment = Generation\ Surplus\ Post\ Processing}$
Generation Curtailment	*Values extracted from PLEXOS Simulation Run* Forecast **Generation Curtailment** is an output of the curtailment study. It represents PLEXOS' dispatch of generators may not reflect the dispatch of generators according to market rules.
Generation Curtailment Post Processing	This step is a result of post processing of the generation output of the curtailment study*.
Curtailment Dispatch Down	$\boldsymbol{Available\ Energy\ Curtailment - Generation\ Curtailment\ Post\ Processing}$ Surplus dispatch down can be calculated for any unit, node, subgroup, area or system can be extracted from the PLEXOS model
Curtailment Dispatch Down (%)	$\frac{\boldsymbol{Curtailment\ Dispatch\ Down}}{\boldsymbol{Available\ Energy\ Surplus}} \times 100$

*Please note that Curtailment Dispatch Down is applied to all generation on a pro-rata basis. However, the availability of renewable energy is dependent on technology type and location, so Curtailment Dispatch Down (%) will vary from area to area and based on technology type.

Table 5-3: Constraint dispatch down calculation

Quantity	Description
Available Energy Constraint	$\boldsymbol{Available\ Energy\ Constraint = Generation\ Curtailment\ Post\ Processing}$
Generation Constraint	*Values extracted from PLEXOS Simulation Run* Forecast renewable generation in the Constraint study is an output of the Constraint study. It represents PLEXOS' dispatch of generators may not reflect the dispatch of generators according to market rules.
Generation Curtailment Post Processing (Grandfathering)	This step is a result of post processing of the generation output of the constraint study*.
Generation Curtailment Post Processing (Pro-rata)	This step is a result of post processing of the generation output of the constraint study*.
Constraint Dispatch Down	$\boldsymbol{Available\ Energy\ Constraint - Generation\ Constraint\ Post\ Processing}$ Surplus dispatch down can be calculated for any unit, node, subgroup, area or system can be extracted from the PLEXOS model
Curtailment Dispatch Down (%)	$\frac{\boldsymbol{Constraint\ Dispatch\ Down}}{\boldsymbol{Available\ Energy\ Surplus}} \times 100$

*Please note the Constraint Dispatch Down is applied to generators within the subgroup where the network constraint occurs, as described in Section 5.3.3.

When grandfathering of constraints dispatch down methodology is applied, Constraint Dispatch Down is applied to non-priority generators ahead of priority generators. If the constraint is not resolved, priority generators are also dispatched down.

Using pro-rata constraint dispatch down, it is applied pro-rata regardless of priority status. Again, the Constraint Dispatch Down (%) will vary depending on area and technology type.