# Imperfections Charges Forecast

## Tariff Year 2025/26

**30th May 2025**

EirGrid SONI

Contents

| Revision History | | |
|---|---|---|
| **Revision** | **Date** | **Description** |
| v1.0 | 30/05/25 | Issued to RAs |
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| | | |

# Abbreviations and Acronyms

| Acronym (abbreviation) | Term |
|---|---|
| AGU | Aggregated Generator Unit |
| AIRAA | All Island Resource Adequacy Assessment |
| BETTA | British Electricity Trading and Transmission Arrangements |
| BMPCOP | Balancing Market Principles Code of Practice |
| CCGT | Combined Cycle Gas Turbine |
| CEP | Clean Energy Package |
| COD | Commercial Offer Data |
| CRU | Commission for Regulation of Utilities |
| DBC | Dispatch Balancing Costs |
| DSU | Demand Side Unit |
| EWIC | East West Interconnector |
| GB | Great Britain |
| GTC | Gas Transportation Charges |
| GPI | Generator Performance Incentive |
| HILP | High Impact Low Probability |
| MW | Megawatt |
| MWh | Megawatt hour |
| NPDR | Non-Priority Dispatch Renewables |
| NTC | Net Transfer Capacity |
| OCGT | Open Cycle Gas Turbine |
| OSC | Other System Charges |
| PNs | Physical Notifications |
| RA | Regulatory Authority |
| RES | Renewable Energy Sources |
| RoCoF | Rate of Change of Frequency |
| SDP | Scheduling & Dispatch Programme |
| SEM | Single Electricity Market |
| SEMC | Single Electricity Market Committee |
| SEMO | Single Electricity Market Operator |
| SNSP | System Non-Synchronous Penetration |
| T&SC | Trading and Settlement Code |
| TCG | Transmission Constraint Group |

| | |
|---|---|
| TEG | Temporary Emergency Generation |
| TOOT | Taking Out One at a Time |
| TOD | Technical Offer Data |
| TSOs | Transmission System Operators |
| UK | United Kingdom |
| UUC | Unconstrained Unit Commitment |
| UR | Utility Regulator |
| VOM | Variable Operation and Maintenance |

# 1. Summary

EirGrid and SONI are Transmission System Operators (TSOs). In this role, the TSOs take actions to ensure the continuous supply of power and system security to customers across the system in real time. As a result, the TSOs may have to dispatch or call on some power generators differently from the market schedule. The cost of these actions is known as Imperfections Costs. These costs are paid from the money received from suppliers through Imperfection Charges.

The purpose of this submission is to set out the TSO's' proposed values for 2025/26 Imperfections Charges which are then assessed and decided upon by the Regulatory Authorities (RAs).

## 1.1. What are Imperfections Charges and why is a forecast needed?

Imperfections Charges recover the total expected costs of managing the transmission system safely and securely. In operating the transmission system, we work to ensure supply of power and system security to customers across the system in real time. That means we may have to dispatch or call on some power generators differently from the market schedule. The cost of these actions we take to keep the system balanced and secure is funded through the Imperfections Charge.

The RAs assess and the Single Electricity Market Committee (SEMC) decides on the level at which the Imperfections Charge is to be set for the upcoming Tariff Year which runs from 01 October 2025 to 30 September 2026. The Imperfections Charge parameters is set before each Tariff Year, which is used to calculate the CIMP component as per section F.12 of Trading and Settlement Code. The TSOs must submit a report to the RAs which sets out their forecast of Imperfections Charges Parameter for the upcoming Tariff Year. The estimates provided in this report are based on the best available data at the point of preparation. Most of the input data for the PLEXOS model was compiled as of April 2025. For the K Factor determination, the input data was taken as of May 2025.

The Imperfections Charges Parameters are made up of two parts:

1. **Imperfections Price (PIMP)(€/MWh)**

   We calculate PIMP by dividing the anticipated imperfections cost by the forecast demand. When calculating this anticipated imperfection cost, we also consider the K Factor. The K Factor considers adjustments from previous years, where imperfection costs were more or less than we expected.

2. **Imperfections Charge Factor (FCIMP)**

   In the context of section F.22.2.5[1] of the Trading and Settlement Code (**TSC**), provides scope to adjust the FCIMP (which by default is set to 1) in situations where the Imperfections Price is significantly less or more than we need to recover the anticipated costs. At the time of writing

[1] If the Market Operator considers that either the current rate of draw-downs being made under the Market Working Capital Credit Facility or the amount drawn-down under the Market Working Capital Credit Facility specified in a notice to Participants under F.22.2.4 is such that there is likely to be a reduction in payments to Participants under paragraph F.22.3.1, then the Market Operator shall:

(a) investigate an increase in the level of the Market Working Capital Credit Facility, and may make a proposal to the Regulatory Authorities under paragraph F.22.1.1;

(b) identify any other measures available to it under this Code that, solely to the extent practicable in the circumstances, the Market Operator considers reasonable to lessen the likelihood of making a reduction of payments to Participants under paragraph F.22.3.1, including, but not limited to, making a Modification Proposal, proposing revisions to the Imperfections Charge Factor under paragraph F.12.1.4 (having regard to the need of Suppliers to provide adequate notice of tariff changes to their customers) or any combination of measures which the Market Operator considers appropriate in the circumstances; and

(c) submit a report to the Regulatory Authorities outlining the outcome of its considerations under paragraphs F.22.2.5(a) and F.22.2.5(b).

this submission, we do not propose any change to the Imperfections Charge Factor for 2025/26 Tariff Year.

After we make our submission to the RAs, they assess and make a recommendation to the SEMC who decide on the above Imperfections Charges Parameters for the applicable period. The Single Electricity Market Operator (SEMO) then levies this charge on all supplier units based on their metered demand.

## 1.2. Anticipated Imperfections Charges Parameters for 2025/26

We calculated the anticipated Imperfections Charges Parameters, based on several assumptions and expected conditions for the 2025/26 tariff year period (01/10/2025 to 30/09/2026). The table below shows our forecast for the Imperfection Charges Parameters, with the amounts approved for last year shown alongside for reference.

| | TSOs' Submission 2025/26 (€m) | RA Allowed Amount 2024/25 (€m) | Difference (€m) |
|---|---|---|---|
| Anticipated imperfections costs (€m) | 699.81 | 633.62 | 66.19 |
| K Factor (€m) | 183.43 | -66.41 | 249.84 |
| Anticipated imperfections cost less K Factor adjustment (€m) | 883.24 | 567.21 | 316.03 |
| Forecast demand (GWh) | 39,650 | 38,800 | 850.00 |
| Imperfections Price (PIMP)(€/MWh) | 22.28 | 14.62 | 7.66 |
| Imperfections Charge Factor (FCIMP) | 1.0 | 1.0 | 0.0 |

*Table 1 TSOs' Submission of Anticipated Imperfections Charges Parameters*

## 1.3. Main drivers in 2025/26 anticipated Imperfections Charges Parameters

The forecasted imperfection cost for 2025/26 is €699.81m. This is an increase of €66.19m compared to the €633.62m approved by the RAs in the preceding Tariff Year.

This includes €91m for potential payments to participants under the Clean Energy Package Article 13(7), as discussed further in Section 4.3.

Excluding the provision for Clean Energy Package Article 13(7) (CEP), we forecast a spend of €608m for the 2025/26 tariff year. This estimated cost aligns with recent trends (excluding any provision for CEP liability) as shown in the graph below.

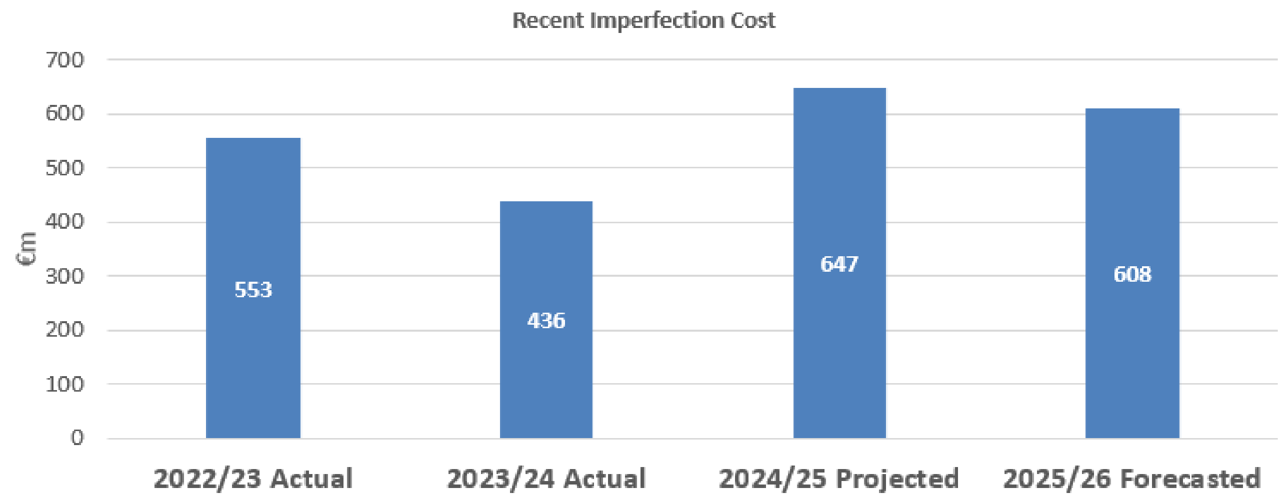



*Figure 1 Benchmark of 25/26 Forecast Submission with Recent Costs excluding provision for CEP Article 13(7)*

Overall, our modelling suggests an overall forecast which is lower than our 2024/25 projected imperfections costs, but overall higher than 2023/24 actual costs (ex-k factor and ex-CEP provisions).

Based on our Plexos model, we have identified the following drivers that are predicting an increase in costs relative to the 2023/24 actual costs:

- Increased renewable capacity: While our model shows that increasing renewable capacity leads to lower overall system generation production costs and therefore anticipated market price, it tends to elevate Imperfection Costs. This is because it now becomes less likely for units to clear in the market that are necessary to satisfy operational constraints for system security requirements and will therefore have to be run by an out of market action by the TSO's at an Imperfections Cost. It should be noted that the savings from lower generational costs outweigh any increase in Imperfections Costs.
- Increased interconnector capacity: Since the connection of Greenlink, a new 500 MW capacity Interconnector coupled with reduced marginal costs in neighbouring markets have resulted in increased overall Imports from The UK BETTA market to SEM as per recent trends. While this drives down the market price for similar reasons above this tends to elevate Imperfection Costs. Units that would otherwise have cleared in the market are now required to be run without clearing in the market to satisfy system security requirements at an Imperfection Cost.
- Generator outages: the model indicates that outages forecast for 25/26 are more costly than those of the recent past. Generator outages have proven to be a significant driver for Imperfections Costs throughout the 2024/25 tariff year to date. This is because when a standard unit (which generally satisfies certain Transmission Constraint Groups) is on outage this must be replaced by an alternative unit. Many of these alternative units were new during the 23/24 period, so previously we had to use proxy data based on participant data submitted over the 2023/24 tariff year (which was the best information available at the time). The actual Commercial Offer Data of some of these alternative units has proven to be much greater than the proxy data previously used, which means that including the actual Commercial Offer Data of these replacement units in our Plexos model suggests that generator outages will have a much greater impact on Imperfection Costs in comparison to previous years (an observation which aligns with 2024/25 trends year to date).
- Transmission outages: Outages by their nature reduce the capability of the system to transfer power securely in line with market outcomes and will lead to higher Imperfection costs. Due to the level of activity planned on the Network to facilitate the various customer connections and network enhancements over the next number of years, required to meet the objectives set out in the Operational Policy Roadmap, Transmission Outages will continue to be an increased driver of Imperfections Costs year on year for the next number of years including 2025/26.

On the other hand, our Plexos model suggests that the following factors will exert downward pressure on costs:

- Commercial Offer Data: The model shows that forecasted commercial offer data although increasing and having a negative impact on market price, will reduce Imperfections costs in 2025/26 due to the price differential between market price and out of market action reducing.
- Wholesale fuel and carbon prices: Lower fuel and carbon prices are forecasted for the 2025/26 tariff year and as expected has shown an overall reduction in all expenses including Imperfections Costs. Imperfections Costs are extremely volatile to fuel and carbon prices as we have a power system heavily reliant on fossil fuel-based power generation.
- Total Energy Demand: Forecasted higher energy demand results in reduction of DBC as this allows must run generator units which are essential to meet network stability requirements to clear in the market to meet energy demand thus reducing overall imperfection cost.

# 2. Introduction

## 2.1. Purpose of this report

The purpose of this report is to fulfil our obligations under F.12.1 Part B of the Trading and Settlement Code. This Code states that we must set out proposed values for the Imperfections charges parameters for the upcoming tariff year (see Appendix 1 for the relevant sections of the Trading and Settlement Code).

The report must detail any relevant research or analysis we carried out and how we can justify the specific values we propose. The RAs then assess and the SEMC decides on the values to be used during the Tariff Year.

This submission reflects the forecast of the revenue required from the Imperfections Charge for the 12-month period from 01/10/2025 to 30/09/2026, referred to as the Tariff Year 2025/26. It also reflects the K Factor (the adjustment for under or over recovery in the previous year). The relevant sections of the Trading and Settlement Code are shown in Appendix 1.

## 2.2. Constraint costs

EirGrid and SONI are Transmission System Operators (TSOs). In this role, the TSOs take actions to ensure the continuous supply of power and system security to customers across the system in real time. As a result, the TSOs may have to dispatch or call on some power generators differently from the market schedule. The cost of these actions is known as Imperfections Costs. Generators receive constraint payments to keep them financially neutral for the difference between the market schedule and the actual dispatch.

Constraint costs therefore arise to the extent that there are differences between the market determined schedule of generation to meet demand (the ‘market schedule’ or ‘Day Ahead schedule’) and the actual instructions issued to generators (the ‘actual dispatch’ or ‘balancing market dispatch’). A generator that is scheduled to run by the market but which is not run in the actual dispatch (or run at a decreased level) is ‘constrained off/down’; a generator that is not scheduled to run or runs at a low level in the market, but which is instructed to run at a higher level in reality is ‘constrained on/up’. There can be associated Imperfection costs for both changes in generator dispatch quantities.

Section 2.2.1 below describes the typical areas that can lead to a difference between the market schedule and actual dispatch, and hence constraint costs.

### 2.2.1. Why do Constraint Costs Arise?

*Reserve*

To ensure the continued security and stability of the transmission system in the event of a generator tripping, the TSOs instruct some generators to run at lower or higher levels of output based on the technical characteristics of the unit, where it can provide an automatic fast response known as reserve to counter tripping events. To maintain the demand-supply balance, some generators will be constrained off/down while others will be constrained on/up, again leading to the actual dispatch deviating from the market schedule, which does not account for reserve requirements.

*Transmission*

To ensure the safe and secure operation of the transmission system, it may be necessary to dispatch specific generators to certain levels to maintain compliance with the Operational Security Standards. Generators may be both constrained on/up or off/down thus leading to the actual dispatch deviating from the market schedule, as the market schedule does not account for any transmission constraints.

*Market Modelling Assumptions*

Due to mathematical limitations, approximations and assumptions in the market schedule software, the market schedule will not always be technically feasible. This is mainly due to a number of generator technical capabilities and interactions not being specifically modelled (e.g., the market assumes a single generator ramp and loading rate, whereas in reality many generators have multiple ramp and loading rates). In real-time dispatch, the TSOs (and generators) are bound by these technical realities and so the market schedule and dispatch will differ.

*Managing Constraint Costs*

Constraint costs will inevitably arise due to the factors described above and they are also dependent on underlying conditions. Some of these conditions, such as fuel costs, participants bidding behaviour/ strategy, wind/solar conditions, generator forced outages, trips, transmission network availability and system demand are outside of the TSOs' control. However, the TSOs continually monitor constraint costs and the drivers behind them to ensure that costs which are within their control are minimised.

## 2.3. Relationship between 'constraint costs', 'Dispatch Balancing Costs (DBC)' and Imperfections Charges

As detailed in Section F.12.2.1 Part B of the Trading and Settlement Code the Imperfections Charge is levied to recover the anticipated costs for the following:

- Dispatch Balancing Costs (DBC) (less Other System Charges[2]);
- Fixed Cost Payments and Charges; and
- the adjustments for previous years as appropriate.

Table 2 describes the SEM Settlement Components that are part of imperfections costs and Figure 2 shows the relationship between constraint costs, DBC and imperfections costs.

| Dispatch Balancing Cost | Description |
|---|---|
| Constraint Costs | |
| CPREMIUM | Paid when an offer is scheduled in balancing (and delivered) at an offer price above the imbalance settlement price. |
| CDISCOUNT | Paid when a bid is scheduled in balancing (and delivered) at a bid price below the imbalance settlement price. |
| CABBPO/ CAOOPO | Bid Price Only and Offer Price Only Payments and Charges: an adjustment payment or charge to result in net settlement at the offer price for increments, or bid price for decrements, for undo actions on generators. |
| CCURL | Adjustment payment or charge to result in net settlement at a specific curtailment price for curtailment actions on generators. |

[2] Other System Charges are charges levied outside the Single Electricity Market by the TSOs. They include Trip Charges, Short Notice Declaration charges and Generator Performance Incentive charges.

| | |
|---|---|
| Other Dispatch Balancing Costs | |
| CUNIMB | Uninstructed Imbalance Charges:<br>CUNIMB are charges for imbalances and bids and offers accepted in balancing but not delivered, which were outside of a tolerance. Undelivered quantities are settled at the imbalance settlement price. |
| CTEST | Testing Charges which are applied to units under test. |
| CEADSU | Energy payments for Demand Side Units (DSUs) at times of energy scarcity when imbalance price exceeds the strike price |
| **Fixed Cost Payments and Charges** | |
| CFC | **Component** Fixed Cost Payment or Charge:<br>Payments for additional fixed costs incurred, or charges for fixed costs saved from dispatching a unit differently to its market position, if not sufficiently covered through the unit's other payments or charges. |

*Table 2 Dispatch Balancing Cost and Fixed Cost Payments and Charges*

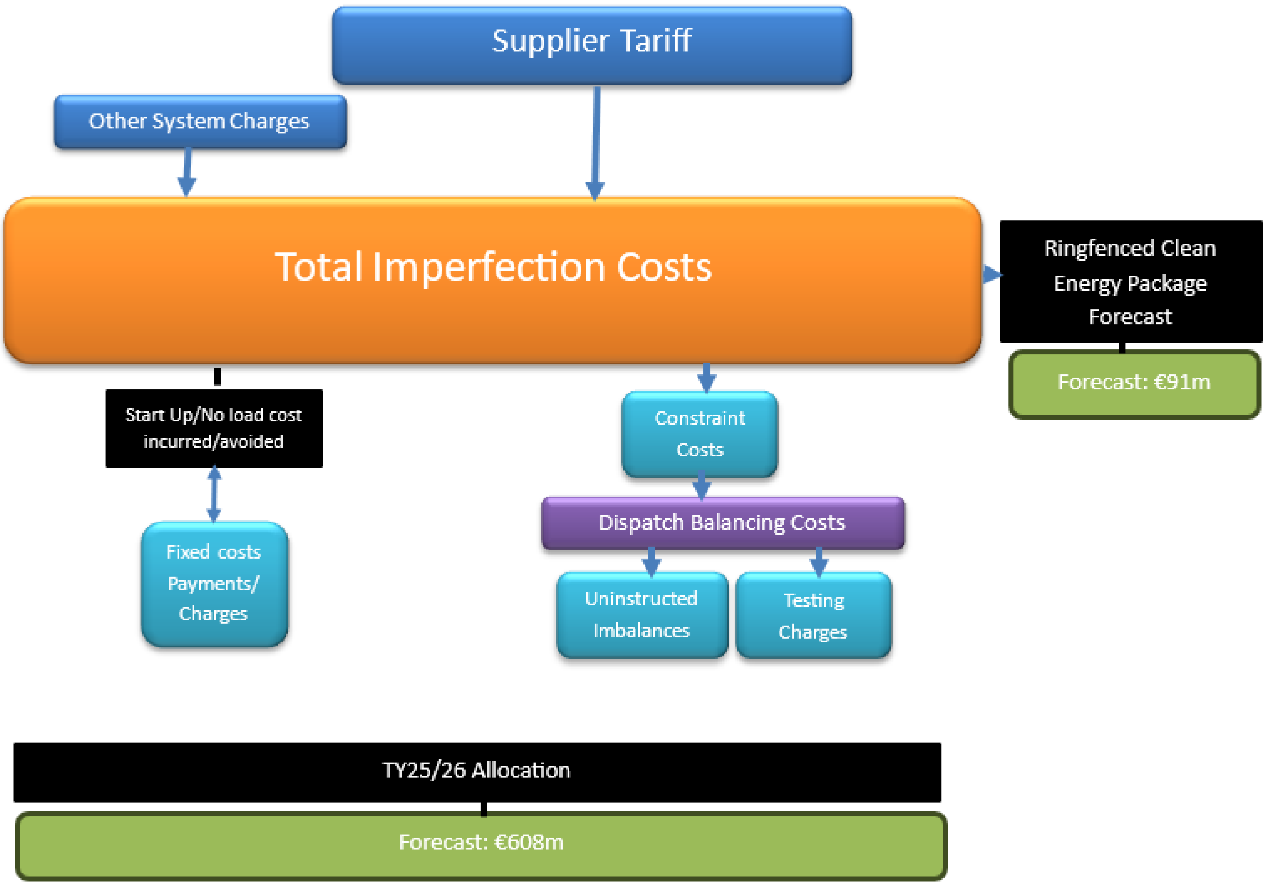



*Figure 2 Relationship between Constraint Costs, Dispatch Balancing Costs and Imperfections Costs*

# 3. Forecasting Constraint Costs

## 3.1. What method did we use in forecasting Constraint Costs?

In making our forecast of Constraint Costs, we combined the following methods:

*PLEXOS model*

This is a modelling tool that we use to simulate the Single Electricity Market (SEM). It can be used to forecast constraints over a year using the best available data and assumptions. PLEXOS is a causal forecast model; it explicitly incorporates the relationships between underlying factors such as fuel costs, outage schedules and constraint/reserve requirements.

*Supplementary Model*

Some constraints cannot be accurately modelled in PLEXOS, so for these we do supplementary modelling. We then add the outcome forecast of this supplementary modelling on top of the PLEXOS model to arrive at the overall Imperfections forecast. Much of the forecasts in the supplementary model are based on historic data. It assumes that the past will be a good indication for forecasting the future.

The forecasting methods we have used for the 2025/26 Forecast are consistent with previous years' approach.

*Model Validation*

As part of our imperfections work, we also run a Backcast Model. The Backcast process starts after the last full tariff year has completed. This exercise starts withthe original forecast model as a base for the tariff year in question, but rather than running the model with the same values assumed during the forecast, we update the model using actual data outturn data from the period. This allows us to measure Backcast outputs against actual data, validates the model, and provides insight which can improve future forecasts. All historic Backcast Reports are published on the SEMC website.

## 3.2. PLEXOS Forecast Model

The PLEXOS model can produce an hourly schedule of generation, with associated costs, to meet demand for a defined study period.

We have set up two PLEXOS models showing the dispatch for each hour over the 2025/26 period:

1. Unconstrained models

   This represents the market schedule (Day-Ahead schedule) of generation dispatch.

2. Constrained model

   This represents the actual generation dispatch. It considers the constraints needed to keep the transmission system secure and reliable.

The constraint costs are then assumed to be the difference between the constrained and unconstrained models (which represents the difference between the cost of actual dispatch and market schedule).

*Key Modelling Assumptions*

PLEXOS uses a detailed model of the transmission and generation systems across the whole island with key inputs such as wholesale fuel costs; generator outage schedules; demand levels; plant availability; and wind/solar profiles.

The model also considers reserve requirements and specific transmission constraints. In Appendix 2 you can read the key assumptions we used to set up the PLEXOS model.

## 3.3. Supplementary Model

PLEXOS captures most forecast constraint costs. However, there are some costs which cannot be modelled in PLEXOS. For the forecast of these additional costs, we use the supplementary model. This model includes the following costs:

### 3.3.1. Additional CPREMIUM and CDISCOUNT

This accounts for the fact that the PLEXOS model does not fully capture SEM settlement rules.

A feature of SEM settlement rules is that if a generator's actual dispatch differs from its market schedule, it gets paid:

- the greater of their offer price and imbalance price, for increments (CPREMIUM); and
- the lesser of their offer price and imbalance price, for decrements (CDISCOUNT), for non-energy actions taken.

Most of this feature of SEM Settlement rules are captured in the PLEXOS model. It captures if the imbalance price is between the generator constrain-down (decremental) offer price and the generator constrain-up (incremental) offer price.

However, PLEXOS does not capture the scenarios where:

- the imbalance price is greater than the generator incremental offer price; or
- the imbalance price is lower than the generator decremental offer price.

To account for these two features of SEM settlement rules, additional calculations are done outside of the PLEXOS model. The calculation involves applying the CPREMIUM and CDISCOUNT market formulae to the dispatch volume change between the unconstrained and constrained models.

Another feature of SEM settlement rules, which could not be captured in PLEXOS, is that generators can sometimes be settled on their simple bids rather than complex bids. The impact of this feature is also accounted for in the supplementary model, based on the proportion of time over the recent past that the generators had been settled on simple offers.

### 3.3.2. Other costs included in Supplementary Model

The following costs are also included in the supplementary model:

- System Operator Interconnector Counter Trades;
- Dispatch of Pump Storage Units;
- Constrained Wind and Solar;
- Energy Imports for Units in System Services modes.

The forecast of these costs is based on historic data; full details of the methodology behind each estimation is outlined in Sections 4.2.2 to 4.2.5.

## 3.4. Forecast Model Limitations

The forecasting of imperfections is a complex study as the actual spend on imperfections has many interacting variables. Therefore PLEXOS, like all models, will never exactly reflect operational reality (even with the supplementary modelling). The model is also limited to being set up for a 12-month study and therefore cannot be used to produce an estimate for any one specific day, months or periods of the year. It is therefore important to consider all results in this context.

### 3.4.1. Risk-factors in Forecast

Several risk-factors should be considered when assessing the anticipated imperfections costs for 2025/26. These factors could individually, or collectively, result in a significant difference between the forecast and actual imperfections costs. They are set out below:

*Wholesale fuel prices*

Wholesale fuel prices are a key input to the forecast. The fuel prices used in the PLEXOS modelling process are based on industry forecasts of long-term fuel prices as of May 2025. Recent prices have been characterised by market volatility.

*SEM Design and modifications to the SEM Trading and Settlement Code*

We have based our assumptions in this submission on the current version of the Market Rules (Version 30, dated 08/11/2024). In respect of the provision regarding Article 13(7) of Regulation (EU) 2019 / 943, we have also considered the SEMC decision SEM/22/009 and the ongoing judicial review process in Ireland in respect of same (see section 4.3 of this submission).

*Items of Uncertain Impact*

Two pending modifications which could have a significant impact on Imperfections Costs that have not been accounted for in this forecast are outlined below. These risks underline the importance of a change to the charge factor to reduce the draw on the working capital facility.

Article 12: SDP-01-Operation of Non-Priority Dispatch Renewables (NDPR)

It is anticipated that this modification as part of the Scheduling & Dispatch Programme will be implemented in the near future. This will mean that several renewable generators will no longer be classified as Priority Dispatch units in the market from this point.

Based on the low production costs of these units it is not anticipated that this will have a significant influence on CPremium payments as the participants incremental price is assumed to be low to reflect this. We also assume that NPDR units that fall into constraint regions will continue to be settled as they are today for dispatch down actions and whose cost is forecasted for in this submission.

There is a potential risk however, that before the system enters curtailment for high frequency minimum generation reasons and the TSOs are dispatching down in the range of NPDR units that this could have a material influence on CDiscount payments (if the dispatch down of NPDR does not set the price and is not marginally flagged out). **There is not enough information available at the time of this submission to quantify this risk and as result it was excluded from consideration**, but we think it is prudent to flag as a risk at this time.

Please note NDPR might also have an influence on the forecast liability for potential payments to participants under Article 13(7) of Regulation (EU) 2019 / 94 as part of the Clean Energy Package, but it was also excluded from consideration for similar reasons (refer to section 4.3 for more details)

SEM-24-046: Demand Side Units: A revised phase 1 solution for energy payments and other issues

As per the consultation paper SEM-24-046[3] dated August 23, 2024, the SEM Committee continues to emphasize the critical role of Demand Side Units (DSUs) in achieving decarbonization targets through effective demand response mechanisms[4]. The proposals built upon previous consultations and decisions,

[2] Update Decision Paper SEM-24-046

[4] Specific consideration was given in the revision to the earlier Phase 1 solution to address the identified "missing money" problem where DSUs may operate at a loss during peak times of demand reduction, despite delivering significant value to the system. The updated plans involve new mechanisms for compensating DSUs, such as the supplier compensation payment aimed at ensuring that the financial burden of energy payments is appropriately distributed among all suppliers through the Imperfections Charge. This strategy aims to alleviate the cost implications for end customers while promoting efficient participation by DSUs, which will continue to be monitored closely for performance effectiveness.

notably SEM-22-090[5], which focused on establishing equitable market rules that enable DSUs to participate alongside traditional generation resources.

As this work remains ongoing, at the time of the 2025/26 Imperfections forecast it is not yet clear the extent to which any proposed changes will be operational within the 2025/26 tariff year. As there was not enough information available to quantify this impact it was thus excluded from consideration, noting that there is scope for an impact on imperfections costs depending on implementation timelines.

*Participant behaviour*

The PLEXOS modelling process has assumed that participants offer into the market in line with their fuel costs and technical availability. We have not made extra provision for any possible bidding strategy by a market participant. We have assumed the Bidding Code of Practice (BCOP) is followed for their complex commercial offer data.

*High Impact, Low Probability Events (HILPs)*

HILPs are low probability transmission, generation or interconnector outages that lead to significant increases in constraint costs. For example, a long-term unplanned outage of a critical transmission circuit due to a fault on an underground cable that could take a long time to repair. This may result in generation being constrained, until the repair can be completed.

*Reduced generator availability*

A reduction in the overall availability of generation could lead to an increase in DBC. This is because relatively more expensive generation may be needed to provide reserve and/or system support, in areas with transmission constraints.

*Variable renewable generation*

Wind/solar generation is inherently unpredictable and can be a significant factor in imperfections cost.

*Forced outages of transmission plant*

The forced outage of a transmission plant may lead to increased DBC due to resultant generator and/or transmission constraints. The outage of certain key items of the transmission system can increase DBC significantly.

*Testing charges*

There is no specific DBC provision for:

- new units that will be under test before they are commissioned; or
- units returning from a significant outage.

We assume that the testing charges will offset the additional DBC incurred. This will primarily consist of constraints, due to out-of-merit running.

However, the testing charges do not cover any transmission-related constraints that arise due to new unit commissioning (as these are difficult to predict in advance). There is no provision for any future changes to testing procedures or T&SC modifications that may result in increased costs.

*Additional security constraints*

We have prepared this forecast using the best estimate of operational policies that will be in effect for the tariff year. As the system develops, these policies may no longer be required, or additional security constraints may be required. This could result in a change in constraint costs.

[3] MOD_02_23 DSU Energy Payments - Decision Paper SEM-22-090

# 4. Forecast Constraint Costs

This section sets out our forecast of imperfections costs for the tariff year 2025/26. Our forecast of 2025/26 Imperfections Costs alongside values for the 23/24 Backcast is shown in Table 3.

| Component | 2025/26 Forecast (€m) | 2023/24 Backcast (€m) | Difference(€m) FC - BC |
|---|---|---|---|
| PLEXOS model | 529.56 | 399.59 | 129.97 |
| Supplementary model | 79.25 | 66.07 | 13.18 |
| **TOTAL** | 608.81 | 465.66 | 143.15 |

*Table 3 2025/26 Imperfections Forecast*

The following sections detail the PLEXOS and supplementary forecast models.

## 4.1. PLEXOS results

The 2025/26FC Model was developed using the 2023/24 Backcast Model as its starting point. This is the same approach as last year and further detail is provided below.

*2023/24 Backcast Model*

The 2023/24 Backcast Model uses various inputs based on actual data for the period 2023/24, resulting in an ex-post adjusted forecast known as the '2023/24 backcast". Detailed information about the 2023/24 Backcast Model, including its description and results, can be found in the report submitted to the RAs accompanying this forecast submission.

Using the 23/24 backcast model as a starting point serves as a validated reference point, as the total backcast costs for 2023/24 fall within the general range of the of the actual costs for that year (outturn variance was 7%). We then incorporated anticipated changes for 2025/26 into this base model to assess their impact.

A summary of the 2023/24 actual costs, the 2023/24 backcast model costs, projected 2024/25 Costs (estimate as of May 25) and 2025/26 Forecast Costs are shown in Figure 3.

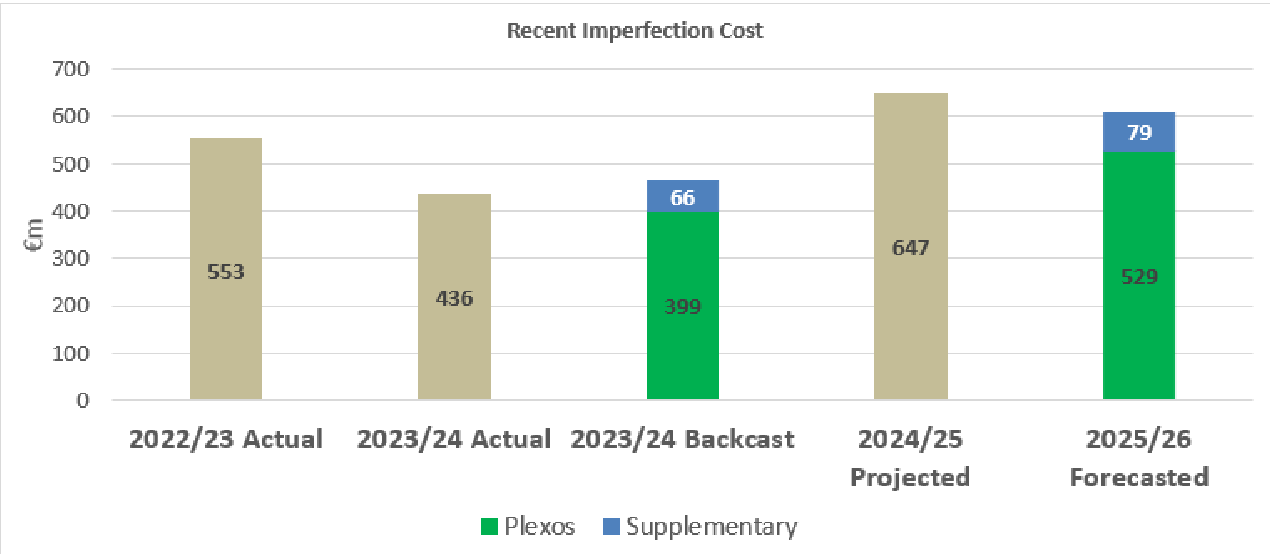



*Figure 3 Recent Imperfections Costs (2025/26 Forecast Costs exclude provision for CEP Article 13(7)*

We have undertaken a "Take-Out-One-at-a-Time" (TOOT) analysis to determine the approximate scale of each single input change relative to the final model. This allows us to see how each individual factor affects costs. This involved starting with the final 2025/26 Forecast model and then taking out one input at a time and replacing it with what was in the previous 2023/24 backcast (which are based on actuals). The difference between the two models is shown in Figure 4 below.

For example, the final 2025/26FC Plexos Model determined a DBC of €529m. This model was then rerun using fuel/carbon input files as per those of the 23/24BC. The result of this updated model was a DBC of €553m. Therefore, the relative impact of the update in the fuel/carbon inputs is €529m - €553m = €-24m. The negative sign indicates a decrease in cost.

The cumulative total of all the changes does not sum to €129m (€529m - €400m, final model cost – starting model cost). This is because €529m reflects the total PLEXOS imperfections when all inputs are updated *simultaneously*, (i.e., at the same time, in the same model), while the values in Figure 4, are essentially different iterations of the same forecast model but where the *forecast* input for a given cost was swapped out for the *actual outturn value* used in the 2023/24 backcast (while keeping all other forecast inputs constant). These scenarios essentially seek to quantify the relative weight of each input on determining the overall forecast by demonstrating how overall imperfections costs might turn out if that input remained static. This exercise demonstrates the highly complex non-linear nature of the model, while providing a view of the relative significance of each input factor.

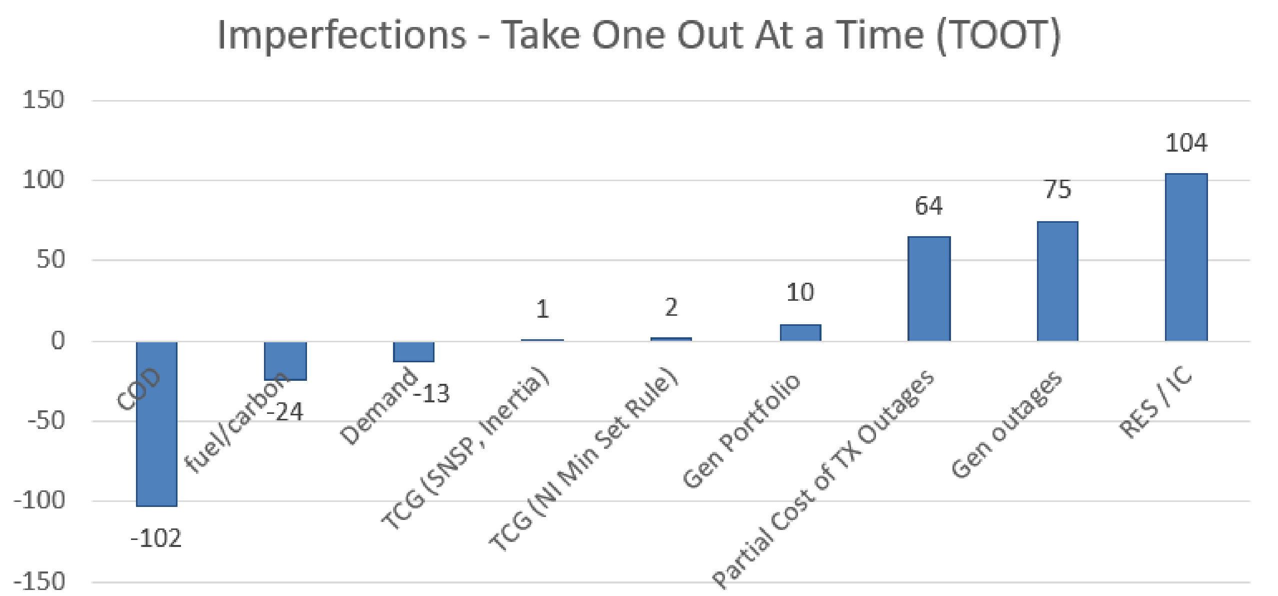



*Figure 4 Taking Out One at a Time (TOOT) Analysis on the 2025/26 Forecast Model (€m)*

The most significant influences on forecast constraint costs shown in the PLEXOS model based on the above analysis are shown below in Table 4.

| Influence | Change to Imperfection cost | Amount in € millions |
|---|---|---|
| Commercial Offer Data | Reduce costs | €-102m |
| Fuel price forecasts are lower than those of 2023/24 BC | Reduce costs | €-24m |
| Update of Demand for 25/26FC from 23/24BC | Reduce costs | €-13m |
| Operational Constraint updates | Increase costs marginally | €3m |
| Generator Portfolio Updates | Increased costs | €10m |
| Partial Cost Representation of Transmission Outages | Increased costs | €64m |
| Forecast generator outages for 2025/26 are greater than those in 2023/24BC | Increased costs | €75m |
| RES Capacity & Interconnector Updates | increased costs | €104m |

*Table 4 The drivers on 25/26 Forecast constraint costs compared to the 2023/24 Backcast*

Further detail on these underlying factors is provided in the following sections.

### 4.1.1. Generator Complex Commercial Offer Data.

We carried out a review of the latest complex commercial offer data submissions of all generator units, with a focus on price quantity pairs, no-load costs and startup costs. Forecast information of commercial offer data for new units which connected onto the system in the 2023/24 backcast period were updated based on actual data.

Following this review, it was determined that there was a general increase in the production costs of units from the data used to represent the 2023/24 backcast period. This had the impact of significantly increasing the market price determined by the constraint model but in turn reduced the price differential between the market price and the out of market actions required to maintain system security. Using the updated representation of Generator COD data in the 2025/26 forecast model resulted in a significant reduction in Imperfections Costs determined as ~€102m in this TOOT step.

### 4.1.2. Fuel Prices/Carbon Prices

Wholesale fuel and carbon prices are a fundamental driver of imperfections costs.

Figure 5 outlines the differences in the fuel prices between the 2023/24 backcast and the 2025/26 forecast. The cost of fuel between these models has decreased. This makes the cost of constraining on out-of-merit generation less expensive and drives a lower production cost in the constrained model. The result is that the disparity between the unconstrained and constrained model production costs decreases, and with it, the DBC.

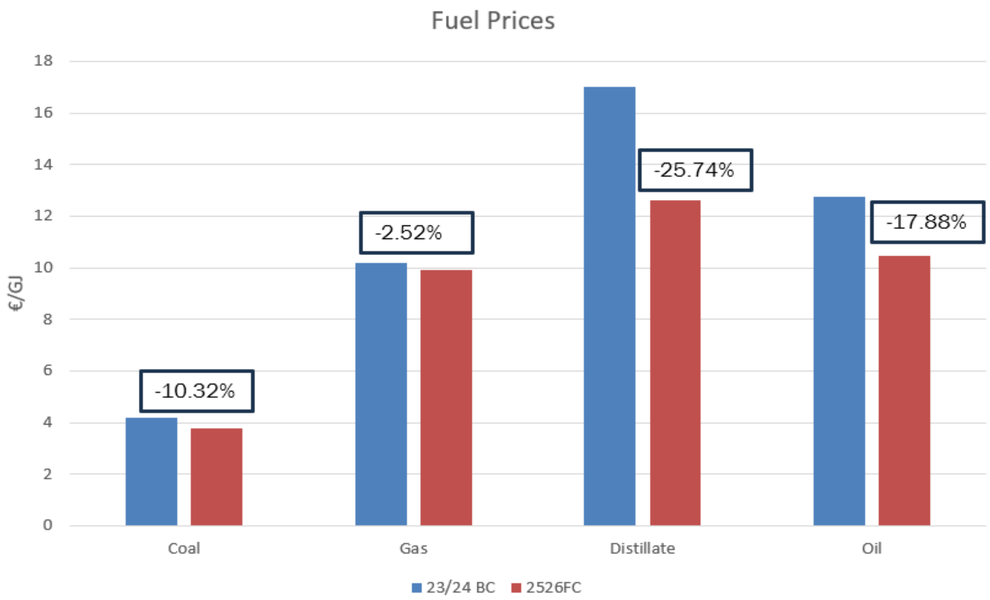



*Figure 5 Fuel Cost Changes from 2023/24 Backcast to 2025/26 Forecast*

As shown in Figure 6 (below), carbon costs have decreased. This results in a minor difference between the constrained and unconstrained model production costs, resulting in reduced Imperfections Costs.

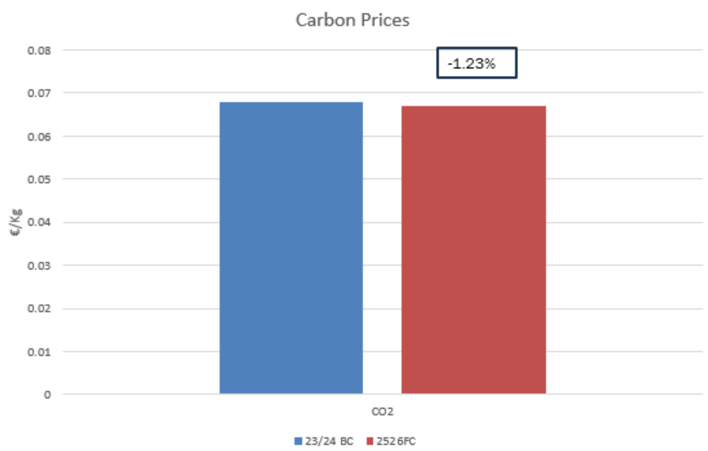



*Figure 6 Model Carbon Cost Changes from 2023/24 Backcast to 2025/26 Forecast*

### 4.1.3. Revised demand

The forecast demand is taken from the median scenario of the All-Island Resource Adequacy Assessment (AIRAA) 2025-2034. This demand has increased by ~5,000 GWh in the 2025/26 Forecast model than that in the 2023/24 Backcast model.

While higher demand puts upward pressure on the market price due to the increased energy that needs to be served this generally has a positive impact on Imperfections Costs. The higher demand increases the likelihood of units to clear in the market that would otherwise have to be run out of market to satisfy System Security requirements at an Imperfections Cost.

This cannot be taken as a definitive rule of thumb however as although out of market actions are reduced under higher demand conditions, remaining out of market actions might have to be taken at higher Imperfections Costs due to the higher market price.

In line with the findings of the AIRAA, there remains a risk of unserved energy over the coming years. This is reflected in the Imperfections PLEXOS model which contains small periods of unserved energy in Ireland. In practice if required this energy will be met by the running of Temporary Emergency Generation (TEG) at no increased Imperfections Cost.

### 4.1.4. Operational constraints

The best estimate of operational policies / Transmission Constraint Groups (TCGs) changes that will be in effect for the Tariff Year has been considered in the model, as summarised in Table 5 below.

| Operational pathway | Treatment in 2025/26 Forecast Model |
|---|---|
| System Non-Synchronous Penetration (SNSP) | 80% |
| Inertia | 23,000MWs[6] |
| All-island Minimum Set Requirement | 7 units throughout 2025/26 model |
| Northern Ireland Minimum Set Requirement | This remains a standard 3 set rule throughout the 2025/26 model but in some scenarios of NI Conventional Generator Availability this is reduced to a 2-set rule with an associated increased Tie-Line Restriction[7] |
| South and South-West Voltage Constraint Groups: STHLO1, STHLO2 and STHHI1 | South and South-West Voltage Constraint Groups no longer considered, and their requirements were removed from the Imperfections forecast model |
| Moneypoint Must Run | The System Security Must Run requirement of a Moneypoint unit is no longer considered and its requirement was removed from the Imperfections forecast model. |

*Table 5 Summary of Operational Policies included in 2025/26 Forecast (as of time of model data freeze, March 2024)*

From our TOOT analysis, it has been determined that none of these changes has had a significant impact on Imperfections Costs on the 2025/26 forecast.

Increasing the SNSP level from 75% to 80% has resulted in the marginal increase in Imperfections Costs of the order of ~€1m. To maximise renewables on the system in line with SEM-11-062 relaxing the SNSP restriction from 75% to 80% has increased the systems capability to do this but the cost of out of market actions to comply with SEM-11-062 under an SNSP limit of 80% is forecasted to marginally increase Imperfections Costs for 2025/26.

The Northern Ireland System has the capability to run with a minimum set rule of 2 large units under certain system conditions and with increased system security controls. This was required for periods of 2025 due to forecasted capacity adequacy concerns due to run hour limitations on some units. For any equivalent scenario of conventional plant availability projected onto the 2025/26 forecast period a Northern Ireland minimum set rule of 2 sets was applied to the forecast model. This was also accompanied by tighter Tie-Line flow restrictions from Ireland to Northern Ireland and vice versa in line with how the system was managed in 2025. Implementing this addition to the model increased Imperfections Costs by ~€2m but the implementation of this rule change is forecast to be required in 2025/26 for system security concerns in Northern Ireland.

Removing the South and South-West Voltage Constraint Groups in Ireland demonstrated negligible Imperfections savings in the 2025/26 Imperfections forecast model. It has been determined that the requirements to satisfy these constraints were either largely cleared by market outcomes or were

[6] Same as existing required but just quoted for completeness

[7] This is consistent with the scenario that occurred in 2025 in which this was reduced to a 2-set rule under certain availability of NI conventional units

achieved by other Transmission Constraint group requirements e.g. The All-Island Minimum Set Requirement.

The Imperfections savings for removing the Moneypoint must run requirement was not determined due to the three Moneypoint units de-registering from the market in advance of the 2025/26 tariff year. This would remove our capability of running the system in this manner anyway so it would not make sense to determine the alternative Imperfections Costs of running the system with this rule applied.

Although, all the above changes have resulted in only very modest impacts on Imperfections Costs, these are all very significant milestones towards achieving the objectives laid out in the Operational Policy Roadmap. The Operational Policy Roadmap aims to achieve the reduction (as much as possible) of all out of market system security requirements on the system. This should yield significant savings in Imperfections Costs which would not have been possible without the changes outlined above being achieved in advance.

### 4.1.5. Conventional Generator Portfolio Changes

In the 2025/26 Forecast model, adjustments were made to account for changes in the generation fleet. These adjustments included factoring in additional thermal generation expected to come online and the retirement of specific thermal coal units. The new conventional plant due to connect to the system is expected to behave like peaking plant and are replacing traditional baseload plant. The overall impact of these changes has led to an increase in costs in the order of €10m.

### 4.1.6. Partial Representation of Transmission Outages

When the system is subject to multiple Transmission Outages, the TSO's are required to restrict the output of generation sources that have cleared in the market to remain compliant with the Operational Security Standards. The cost of these actions come in two forms, the compensation required to be paid to generators that have been restricted and compensation to generators that must be increased to meet the resultant generation shortfall.

As Transmission Outage Programmes are planned well in advance to meet project delivery requirements, the following general principles are followed.

- Due to generation capacity concerns, it is ensured that conventional units that have a high predicable level of availability are unrestricted by Transmission Outages in 0 MW renewable conditions.
- Generation restrictions are permitted by Transmission Outages under high renewable availability system conditions as generation capacity concerns are no longer present.

Whereas in previous years we conducted a desktop exercise based on the indicative transmission outages scheduled to take place during the 2024/25 tariff year, focussing on a representative set of outages, to feed into PLEXOS for estimating the DBC costs, we have improved the estimation approach this year.

As detailed in section 4.1.8 below, the random RES availability profile for the 2025/26 Imperfections forecast was derived from the actual availability profiles that occurred in the 2022/23 backcast period. These profiles were scaled up based on the new available Renewable Capacity planned to be connected throughout 2025/26 and were applied to the PLEXOS unconstrained model to replicate the market outcome. Instead of inputting a selection of Transmission Outages into the PLEXOS constrained model, we adjusted the RES availability profiles by the MWh quantity of renewables that are dispatched down in 2023/24 classified as "TX Constraint" reasons. This accounts for both the base case restrictions that would be automatically carried out by the unconstrained PLEXOS model, as well as the additional restrictions caused by the 2023/24 Transmission Outages.

The unconstrained PLEXOS model then ran additional least cost generation to meet the shortfall at an Imperfections Cost, providing a proxy for partial Imperfections Costs. Adding this to the supplementary item "Constrained Wind" provides an overall proxy for the 2023/24 basecase network restrictions and Transmission Outages that we project to be replicated in the 2025/26 forecast. In our models this amounts to an estimated cost of €64m + €35m = ~€99m.

While we think this approach is more representative, twe think it is prudent to flag below risks and limitations with this approach that could underestimate the Imperfections Costs for Transmission Outages, including:

- In medium to low renewable conditions, some local restrictions might be in place that prevent conventional generation sources from generating their full market position. This will have Imperfection Cost implications that are not accounted for by this approach.
- Once firm Transmission Outage schedules mature, it might be determined that the above principles could not be followed, and generation restrictions of conventional plant in 0 MW renewable conditions might be required to deliver a key infrastructure project.
- Once firm Transmission Outage schedules mature, it might be determined that additional Operational Constraint rules might need to be introduced to facilitate the programme of outages securely at an Imperfections Cost not factored into the above approach.
- There is a continued increase in the quantity of key infrastructure projects requested year on year and therefore an increased level of Transmission Outages are required to occur simultaneously and further into the winter months. Modelling an Imperfections Cost proxy for Transmission Outages based on 2023/24 conditions might under-estimate the cost of the 2025/26 requirement with an anticipated increase in outage requirements.

### 4.1.7. Forecast generator outages

Both scheduled and forced generator outages are considered in the PLEXOS model. Generator scheduled outages are based on the latest available information at the time of the data freeze. Forced outages are modelled with a Generator Forced Outage Probability factor and a Mean Time to Repair, which are both based on analysis of historic data.

The model reveals that generator outages in the 25/26 Forecast have a higher cost impact on imperfections compared to those in the 2023/24 Backcast. The cost impact of generator outages is significantly influenced by other system factors and conditions, including wind levels, other units experiencing forced outages, and demand levels. Generator outages have proven to be a significant driver for Imperfections Costs throughout the 2024/25 tariff year to date. This is because when a standard unit that generally satisfies certain Transmission Constraint Groups is on outage this must be replaced by an alternative unit.

Many of these alternative units were new during the 23/24 period, so previously we had to use proxy data based on participant data submitted over the 2023/24 tariff year (which was the best information available at the time). The actual Commercial Offer Data of some of these alternative units has proven to be much greater than the proxy data previously used, which means that including the actual Commercial Offer Data of these replacement units in our Plexos model suggests that generator outages will have a much greater impact on Imperfection Costs in comparison to previous years (an observation which aligns with 2024/25 trends year to date).

The impact on Imperfection Costs is much greater in comparison to previous years and in line with 2024/25 year to date trends amounting to ~€75m.

### 4.1.8. Updated Renewable Energy Sources (RES) & Interconnector Capacities

As there is a link between interconnector flows and renewable availabilities, these were analysed together rather than individually. Analysing these inputs together resulted in an increase in model costs of €104m.

The availability of renewable generation sources is extremely difficult to forecast to any degree of accuracy a year in advance, as this is driven by ambient conditions. Even so, this input has significant influence on the Interconnector flows. For the 2025/26 Forecast, an annual historical profile of these linked inputs from the 2023/24 backcast period was used to represent the annual variability of these variables over a full Tariff Year.

The 25/26 Forecast predicts an increase in renewable generation from wind and solar compared to the 2023/24 Backcast as these profiles have been scaled upwards based on new connections expected to be present throughout the period. This model shows that this increased level of renewable energy has implications for imperfections costs.

To determine total connections in the model, we considered:

- Actual connections up to the data freeze date (March 2025).
- Anticipated connections post the data freeze date, up to 30/09/26, based on build-out rates from the All-Island Resource Adequacy Assessment (AIRAA) 2025-2034, based on Infrastructure connection project timelines, based on current considerations for Transmission Outage Programmes and based on current considerations for commissioning and testing programmes.

While our model shows that increasing renewable capacity leads to lower overall system generation production costs and therefore anticipated market price, it tends to elevate Imperfection Costs. This is because it now becomes less likely for units to clear in the market that are necessary to satisfy operational constraints for system security requirements and will therefore have to be run by an out of market action by the TSO's at an Imperfections Cost.

The forecasted interconnector flows for 2025/26 are based on fixed flows derived from historic profiles between SEM and BETTA markets from the 2023/24 Backcast period aligned with the RES profiles from the same source.

A 500MW capacity Greenlink interconnector, which is commissioned on 29th January 2025, has been factored into the flows. Recent trends of Interconnector flows from SEM to BETTA were analysed between February and March 2025. These trends were used to scale the imports and exports of the historical 2023/24 profiles due to the new increased Interconnector capacity available on the island. This scaled flow was then allocated in the order of Greenlink, then Moyle and then EWIC to reflect forecasted market outcomes based on the order of losses between the three Interconnectors.

Since the connection of Greenlink and coupled with the lower marginal price of neighbouring markets, recent trends have indicated that this has resulted in increased Imports from The UK BETTA market to SEM. While this drives down the market price for similar reasons to the RES profiles above, this tends to elevate Imperfection Costs. Units that would otherwise have cleared in the market are now required to be run out of market to satisfy system security requirements at an Imperfections Cost.

## 4.2. Supplementary Modelling Results

The supplementary model costs for the tariff year 2025/26 is €79.25m. This represents an increase of €13.18 from the 2023/24 Backcast. The results of model costs and supplementary costs for 2025/26 are summarised, as compared to the 2023/24 Backcast, in the table below.

| Description | 2025/26 Forecast (€m) | 2023/24 Backcast (€m) | Difference (€m) |
|---|---|---|---|
| PLEXOS Model | 529.56 | 399.59 | 129.97 |
| Additional PREMIUM and DISCOUNT impact | 0.00 | 0.00 | 0.00 |
| Interconnector Counter Trades | 19.69 | 11.40 | 8.30 |
| Pump Storage Running | 23.06 | 19.60 | 3.46 |
| Constrained Wind | 34.92 | 28.37 | 6.55 |
| Payment for energy imports for units in system services modes | 1.58 | 6.70 | -5.12 |
| **Supplementary Model Total** | 79.25 | 66.07 | 13.18 |
| **CEP Article 13(7): 01 Jan 20 to 30 Sept 26** | 91.00 | 158.00 | -67.00 |
| **Total** | 699.81 | 623.66 | 76.15 |

*Table 6 Summary of 24/25FC Supplementary Costs compared to 23/24 Backcast Supplementary Costs*

### 4.2.1. Additional CPREMIUM and CDISCOUNT payments and Imbalance Price impact

The imbalance price under the revised SEM arrangements is, at a high level, determined by the incremental and decremental costs of generators used for energy actions in the balancing market. The market pays generators the greater of their offer price and imbalance price, for increments, and the lesser of their offer price and imbalance price, for decrements, for non-energy actions taken.

Most of this extra cost is considered using the production cost based PLEXOS modelling. However, for tariff year 2025/26 the settlement cost components CPREMIUM and CDISCOUNT is negligible therefore no cost is included. This calculation is based on actual imbalance prices, for the period Oct 23 to Sept 24.

This impact was calculated by applying the settlement calculation for the two highest settlement cost components CPREMIUM and CDISCOUNT. The calculation involved applying the CPREMIUM and CDISCOUNT market formulae to the dispatch volume change between the constrained and unconstrained models. A further calculation was run to account for simple price offers, based on the proportion of time generators had been settled on their simple offers, in the last 3 months.

The main driver for the decrease in this component compared to the 2024/25 Forecast is a decrease in the wholesale fuel prices.

### 4.2.2. System operator interconnector countertrading

For the 2025/26 forecast, an allowance of €19.69m for countertrading has been requested. This allowance has been based on actual cost of countertrades to imperfections in the last 12 months from the 1st of May 2024 until the 30th of April 2025.

### 4.2.3. Dispatch of pump storage units

Pump storage units are mostly dispatched in pump mode overnight, to facilitate more priority dispatch generation on the system and minimise levels of curtailment. During the day, the units are often kept at their Minimum Generation levels, to provide positive reserve. This running profile is different than the profile that clears in the Day-Ahead market and subsequently differs from their Physical Notifications (PNs) in the Balancing Market. Thus, there are high CPREMIUMS and CDISCOUNTS paid by the market to pump storage units. PLEXOS cannot capture the pump storage unit offer prices, thus a provision of €23.06m is included in the supplementary modelling. The provision is based on the actual CPREMIUM and CDISCOUNT payments the pump storage units received in the last 12 months from the 1st of May 2024 until the 30th of April 2025

### 4.2.4. Constrained wind and solar

Wind/solar is currently not paid for curtailment in SEM; however, it is paid for constraints. Because the wind in the PLEXOS model has a price of 0 €/MWh, we have included a provision of €34.92m within the supplementary modelling. This figure is based on the actual CDISCOUNT that wind/solar participants received in the last 12 months from the 1st of May 2024 until the 30th of April 2025.

### 4.2.5. Energy imports for units in system services modes

Modification *13_19* was passed to allow for the remuneration of energy consumption for units that are dispatched by the TSOs in system services modes. When in system services mode at ≤0MW generation, these units may consume energy that has to be generated elsewhere. This means a different unit in the balancing market must be re-dispatched to cover it, which ends up as a cost for imperfections.

Analysis and forecasting based on historical unit data and imbalance price data in the 12 months preceding 30 April 2025 indicates an expected annual imperfection cost due to 'Mod 13_19: Payment for Energy Consumption' of €1.58m.

The cost to imperfections of redispatch to cover the imported energy of these units in system services mode was determined by multiplying the relevant energy volumes (for the study period) by the relevant imbalance prices.

Forecasts based on the historical costs are sensitive to any future change in imbalance prices and to annual wind conditions (e.g., higher average wind conditions will result in fewer periods in which system services are provided at ≤0MW generation, and vice versa).

## 4.3. Clean Energy Package Article 13(7)

We seek a provision of €91m for potential payments to participants under Article 13(7) of Regulation (EU) 2019 / 943, noting that the SEMC decision SEM/22/009 is subject to a judicial review process in Ireland[8] . This provision includes €54m for under-estimation of the potential payments for 1st Jan 2020 – 30th Sep 2025 (in the 2024/25 forecast) and €37m for 2025/26.

This provision is sought to ensure sufficient funding to meet any potential liability, without prejudice to the ongoing judicial review process. No payments would be made until the legal process is finally concluded and there is a regulatory approved calculation methodology and payment mechanism in place. We will further engage with the RAs regarding implementation of any payment mechanism.

Key assumptions regarding this provision have been discussed with the RAs and include:

- Compensation for constraint and curtailment volumes from 01 Jan 2020 to 30 Sep 2026, up to market price level (to the extent not already funded by 2024/25 Imperfections Charges).
- Any interest, finance and implementation costs, as well as any amounts that may be recovered from intermediaries, have not been included.
- Forecast based on a "first order" approximation.

[8] High Court [2023] IEHC 620: https://www.courts.ie/acc/alfresco/33acac75-8f1f-4c5e-8078-7303630c4ff7/2023_IEHC_620.pdf/pdf#view=fitH
Supreme Court [2025] IESC 1: https://www.courts.ie/viewer/pdf/bb9de1e0-4a49-4cce-b67d-e210126b69fb/[2025]_IESC_1.pdf/pdf#view=fitH

We note the following matters regarding the forecasting of this provision:

- The forecast is based on an average monthly run based on actual data from the 1st of January 2020 until the 30th of April 2025. The levels of dispatch down on the system over the last two years have increased substantially since the preceding period back to 2020. Accordingly, the current approach has the risk of underestimating the potential payments for 2025/26. Basing a run-rate on average data over the past 2 years would better reflect future potential payments.

Following the go-live of the Scheduling and Dispatch Program in respect of Non-Priority Dispatch Renewable (NPDR) units, it is possible that “curtailment” for NPDR units will be redefined such that some actions currently referred to as “curtailment” would be re-classified as “energy balancing” actions and settled through the Balancing Market in the usual course (including payment to intermediaries where applicable). The 2025/26 forecast does not currently take account of this possible re-classification of “curtailment” actions for NPDR units. In the future, it may be appropriate to allocate a downward factor to the monthly curtailment run-rate determination to reflect any re-classification.

The total forecast potential payments for the 2025/26 tariff year for curtailment reasons is €12m and is based on a monthly run-rate derived from actual data from the 1st of January 2020 and the 30th of April 2025 and includes historical data from units that will be classified as NPDR at go-live of the Scheduling and Dispatch Program in respect of Non-Priority Dispatch.

If any future determination found that such re-classification should not have occurred and required retrospective payment of curtailment compensation for all actions, it is noted that (i) there is a risk that the provision for potential payments would not be sufficient if a downward factor has been applied in forecasting NPDR unit curtailment compensation; and (ii) it is assumed that payments for “energy balancing” actions may not be recoverable.

# 5. K Factor submission

The K Factor adjusts for previous Tariff Years under or over recovery.

The calculation of the Imperfections K Factor for inclusion in the 2025/26 tariff is made up of two elements, the Actual Y-1 K factor and the Estimated within-year K factor. These are captured in the table below:

| Description | €m |
|---|---|
| Actual Y-1 Actual K Factor - 2023/24 K is an Under recovery | (16.37) |
| Estimate within Year K Factor - 2024/25 K Factor forecast Under Recovery | (167.06) |
| **Total Forecast Imperfections K Factor for inclusion in the 2025/26 tariffs (net Under Recovery)** | **(183.43)** |

For this period a **net Under Recovery of €183.43m** is anticipated and thus will be **added in** the imperfections forecast for 2025/26. Due to the scale of the K, the TSOs did engage with the RAs regarding the possibility of increasing the charge factor during the 2024/25 tariff year to reduce the forecast 2024/25 K factor to be recovered in 2025/26. A decision was taken by the SEMC not to increase the charge factor.

## 5.1. Actual Y-1 K Factor 2023/24

There was a cash under recovery of €19.54m in 2023/24 tariff year which included a previous over recovery forecast position of €91.17m (ref. SEM-23-067) K Factor as built into the tariffs. Adding this K Factor from previous years gives an actual K Factor over recovery of €71.63m arising for the 2023/24 year. However, in calculating the 2024/25 tariff, there was an estimated €88m over-recovery for 2023/24 included (ref. SEM-24-064). Taking this figure into account results in an **outturn under recovery of €16.37m** for tariff year 2023/24. This under recovery will be added to the imperfections forecast revenue.

## 5.2. Estimate within Year K Factor 2024/25

The Estimated within year (Y) K Factor (2024/2025) is a forecast of the financial position, as reflected in the accounts, as at the end of September 2025. This must take the following into consideration:

- The actual imperfections costs against the forecast and forecast trend to year end;
- Any resettlement costs from previous periods (M+13 etc.) that fall within the period.

**Imperfections Costs**

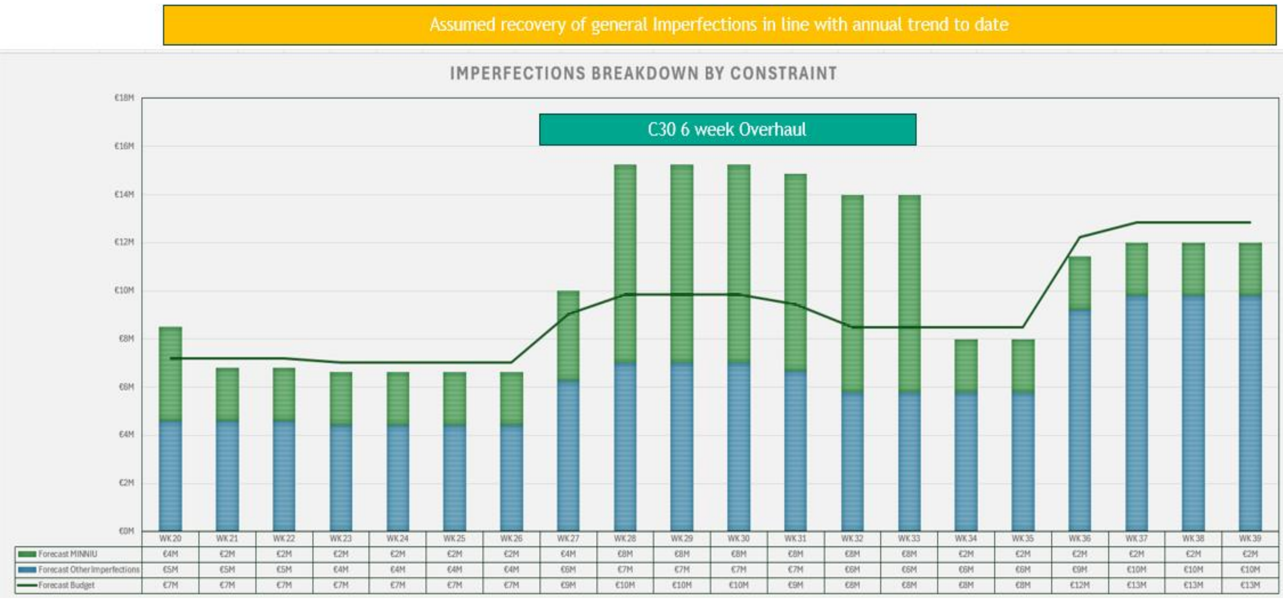
There are two main factors influencing the within year forecast K factor for 2024/2025 - that is the estimated outturn expenditure against forecast and the estimated outturn revenue against forecast.

There has been significant variance seen between our Imperfections forecast and actual costs on the system for the first 7.5 months of the 2025 Financial Year with an overspend against forecasted Imperfections of ~€130 million. The primary contributory factor to this is the challenges encountered in satisfying the Northern Ireland (NI) Security of Supply dynamic stability requirements in a cost-effective manner most notably satisfying the Minimum NI units Transmission Constraint Group (MINNIU). The main factors associated with this are outside of the TSOs control.

The TSOs have estimated that if the influence of this unforeseen driver was removed then the underlying Imperfections forecast is performing quite well with an estimated €22.8 million underspend.

| ***YTD Details*** | ***01/10/24 - 10/05/25*** |
|---|---|
| YTD Budget | €287.72 million |
| YTD Imperfection Costs (-OSC) | €418.21 million |
| Sum of Variance | €130.36 million |
| Variance % | 46% |
| Estimate of under forecast of MINNIU | **-€153.2m** |
| Forecast Performance taking out MINNIU Influence | **+€22.8m** |
| Annual Imperfection Budget | €475.62 million |

In determining the projection for imperfection costs for the next 4.5 months, we used the range of recent historical costs as a starting point. The forecast performance is quite strong when the impact of the MINNIU influence is isolated showing some degree of underspend (~7.8%). Based on the above, it makes sense to project that underspend in the forecast except where we have more up to date information in relation to key Generator Outages that are foreseen to have a significant impact on Imperfections spend (see reference re six-week outage of Coolkeeragh C30 below)




- **Estimated Outturn Expenditure** = €647.2m [Original - Expected Outturn Spend, €475.62m - €647.2m = €171.58m under recovery)

- **Estimated Outturn Revenue** = €571.73m [Original + 24/25 k factor - Expected Outturn Revenue, €633.62m - €66.41m - €571.73m = €4.52m over recovery)

This would yield an estimated potential under recovery in 2024/2025 of **€167.06m** (€171.58m - €4.52m)

The reason for the difference in "Within Year K factor 24/25" to that estimated in March for the 24/25 Mid-Year Report (-€226.48m = -€231.00 + €4.52m) is we have experienced considerably improved system conditions that has minimised Imperfections Costs. This allowed us to temporarily reduce the Northern Ireland system security requirement from a 3-set to a 2-set must run requirement from the 19th of March until the 11th of April, minimising the requirement to run alternative units that were available at the time (but which would have driven high Imperfections Costs). Further, the return of large Conventional units in Northern Ireland that had been forced off since storm Darragh damage on the 7th of December 2024 ahead of the dates anticipated at the time of the mid-year report also contributed to improved system conditions. The combined effect of this was to improve the within-year k factor forecast by about -€59.42m (-€226.48m - -€167.06m).

**Resettlement**

No notable resettlement of imperfections costs is anticipated over the remainder of this tariff year.

**Summary**

Estimated Outturn 2023/25 = (-€16.37m - -€167.06m) = -€183.43m under recovery

**Total Forecast K Factor to be applied in 2025/26**

The total forecast K is an **under** recovery of **€183.43m** which will be added to the Imperfections forecast revenues.

# 6. Imperfections Charge Factor

Under the current SEM arrangements, as detailed in the Trading and Settlement Code Part B, RA/ SEMC approval is required for the Imperfections Charge Factor (FCIMP).

The intent of this is to enable EirGrid and SONI, when it becomes evident within a given year that the Imperfections Charge is not providing the adequate recovery or is over recovering the anticipated costs, to seek approval from the RAs to increase or decrease the factor. This allows them to increase or decrease the Imperfections Charge to a level which adequately recovers the costs, without requiring an amendment to the underlying approved forecast requirement. This would allow the revenues to be recovered within the given year and thus minimise the K Factor for the relevant Tariff Year.

In accordance with Section F.12.1.1 (b), we are now seeking the approval for the Imperfections Charge Factor to be set to 1 for the period of 1 October 2025 to 30 September 2026.

Given the extent of total DBC , the K Factor as per the current arrangements is of paramount importance (as in principle these costs are 100% pass-through). Should there be an overall imbalance, or an expected imbalance for the tariff period as a whole, either to the account of customers or to the licensees, it is critical that the TSOs best estimate will be provided for through the K Factor to minimise any deviation from adequate recovery.

Section F.22 of Part B of the Trading and Settlement Code addresses actions to be taken in the event of working capital shortfalls. This means the business would cease making payments out if the standby debt facilities' limits were hit. In this context, it is of important that the Imperfections Charge Parameter is set against the full forecast provided in this paper, along with the full K Factor which is being submitted.

Our forecast does not include any charges incurred for the holding, or use, of required banking standby facilities, to provide working capital for the TSOs. We assume that the costs incurred as a result of holding banking standby facilities are recoverable through the Transmission Use of System (TUoS) tariff in Ireland and System Support Services (SSS) tariff in Northern Ireland, under the respective regulatory arrangements.

# 7. Appendix 1: Trading and Settlement Code Extract

The relevant Trading and Settlement Code sections are shown in Table 7 below.

| **F.12.1** | **Setting of Imperfections Charges parameters** |
|---|---|
| F.12.1.1 | The Market Operator shall report to the Regulatory Authorities at least 4 months before the start of the Year, proposing values for the following parameters to be used in the calculation of Imperfections Charges for that Year:<br>(a) The Imperfections Price (PIMPy) in €/MWh for Year, y; and<br>(b) The Imperfections Charge Factor (FCIMPγ) for each Imbalance Settlement Period, γ, in Year, y. |
| F.12.1.2 | The Market Operator's report must set out any relevant research or analysis carried out by the Market Operator and the justification for the specific values proposed. The report may, and shall if so requested by the Regulatory Authorities, include alternative values from those proposed and must set out the arguments for and against such alternatives. |
| F.12.2.1 | The purpose of the Imperfections Charge is to recover the anticipated Dispatch Balancing Costs (less Other System Charges), Fixed Cost Payments and Charges, any net imbalance between Trading Payments, Trading Charges, Capacity Payments and Capacity Charges over the Year, with adjustments for previous Years as appropriate. |

*Table 7 Extract from Trading and Settlement Code Part B Related to Imperfections Charges Parameters*

# 8. Appendix 2: PLEXOS model assumptions

We use PLEXOS to forecast constraint costs. PLEXOS is a production cost model that can produce an hourly schedule of generation, with associated costs, to meet demand for a defined study period. The main categories of data that feed into the PLEXOS model are summarised below:

## 8.1. Key assumptions used in PLEXOS model

Detailed below are the key assumptions used in the PLEXOS modelling process:

| Feature | Assumption |
|---|---|
| Study period | The study period is 01/10/2025 to 30/09/2026 |
| Data freeze | Most of the input data for the PLEXOS model was frozen at the end of April 2025<br>For the K Factor determination, the input data was taken as of May 2025 |
| Generation dispatch | Two hourly generation schedules are examined:<br>• one schedule to represent the dispatch quantities (constrained)<br>• the other to represent the market schedule quantities (unconstrained). |
| Study resolution | Each day consists of 24 trading periods, each 1 hour long. A 6-hour optimisation time horizon beyond the end of the trading day is used to avoid edge effects between trading days. |
| Demand | |
| Load | The forecasted demand was derived from the median scenario of the All-Island Resource Adequacy Assessment (AIRAA) 2025-2034. NI total load and IE total load are represented using individual hourly load profiles for each jurisdiction. |
| Load representation | Load Participation Factors (LPFs) are used to represent the load at each bus on the system. LPFs represent the load at a particular bus as a fraction of the total system demand. |
| Generator house loads | These are accounted for implicitly by entering all generator data in exported terms. |
| Generation | |
| Generation resources | Generation resources are based on the All-Island Resource Adequacy Assessment (AIRAA) 2025-2034 and REMIT data |
| Fuel and carbon prices | Fuel/carbon prices for 2025/26 are based on the long-term fuel forecasts from Thomson-Reuters Eikon and the US Energy Information Administration. |
| Production costs | Calculated through PLEXOS. The inputs to PLEXOS were based on analysis of actual bids.<br>1. Fuel/carbon cost (€/GJ)<br>2. Piecewise linear heat rates (GJ/MWh)<br>3. No-Load rate (GJ/h) |

| Feature | Assumption |
|---|---|
| | 4. Variable Operation and Maintenance Costs (€/MWh)<br>5. Gas Transportation Charges (GTC) (€/GJ) for gas units<br>6. Start energies (GJ) |
| Generation constraints (TOD) | Based on the data Technical Offer Data (TOD) in the SEM, the following technical characteristics are assumed:<br>1. Maximum Capacity<br>2. Minimum Stable Generation<br>3. Minimum up/down times<br>4. Ramp up/down limits<br>5. Cooling Boundary Times |
| Generator scheduled outages | 2025 and 2026 maintenance outages are based on provisional outage schedules. |
| Forced outages | Forced outages of generators are determined using a random number generator. Forced Outage Rates and Mean Times to Repair is based on analysis on historic outage data. |
| Hydro generation | Hydro units are modelled using daily energy limits. Other hydro constraints (like drawdown restrictions and reservoir coupling) are not modelled. |
| Priority dispatch generation | Wind and solar generation resources are based on megawatt (MW) currently installed plus an anticipated rate of connection as detailed in the AIRAA-2025-2034 |
| Security constraints | Since a DC linear load flow is used, voltage effects and dynamic and transient stability effects will not be captured. System-wide and local area constraints have been included in the model as a proxy for these issues. |
| Demand Side Units (DSU) and Aggregated Generator Units (AGU) | Demand Side Units and Aggregated Generator Units are modelled explicitly. |
| Interconnector flows | Interconnector flows with Great Britain (GB) are forecast based on actual flows delivered in 2023/24 with adjustments to consider the additional interconnector capacity available with Greenlink and the order of losses between the three Interconnectors on the island. |
| Operational Pathways to 2030 milestones | Operational Constraints were assumed based on the latest available information as of the data freeze.<br>System Non-Synchronous Penetration (SNSP) is set at 80% in the constrained PLEXOS model from Oct 2025.<br>During the year, it is assumed that:<br>• the minimum number of sets is 7 sets,<br>• that the minimum level of inertia is 23 GWs. |
| Transmission | |
| Transmission data | The transmission system input to the model is based on data held by the TSOs. |
| N-1 contingency analysis | Principal N-1 contingencies, based on TSOs operational experience, are modelled. |
| Transmission constraints | Transmission constraints are only represented in the constrained model. The market schedule run is free of transmission constraints. |

| Feature | Assumption |
|---|---|
| Network load flow | A DC linear network model is implemented in the PLEXOS model. |
| Ratings | Ratings for all transmission plant are based on figures from the TSOs' database. |
| Louth-Tandragee tie-line transmission limits | The North-South tie-line is not restricted in the unconstrained SEM-GB model. The Net Transfer Capacity (NTC) is modelled for the constrained schedule, which is assumed to be 450 MW N-S and 350 MW S-N. |
| Forced transmission network outages | Forced transmission network outages have not been explicitly included in the model |
| Ancillary Services | |
| Operating reserve | Primary, Secondary, Tertiary 1 and 2, and Replacement Reserve requirements are modelled. |
| Reserve characteristics | Simple straight back and flat generator characteristics are modelled. Reserve coefficients are modelled where required. |
| Reserve sharing | Minimum reserve requirements are applied to each jurisdiction, with the remainder being shared. These requirements are per the current reserve policy at the time of the data freeze |
| Other reserve sources | For this forecast that DSUs, interconnectors and batteries will also provide reserve in the model. |