Imperfections Charges Forecast

Tariff Year 2024/25

Contents

Revision History		
Revision	**Date**	**Description**
v1.0	31/05/24	Issued to RAs
v2.0	12/06/24	Reissued to RAs with minor wording updates
v3.0	24/06/24	Reissued to RAs with minor wording updates

Abbreviations and Acronyms

Acronym (abbreviation)	Term
AGU	Aggregated Generator Unit
BMPCOP	Balancing Market Principles Code of Practice
CCGT	Combined Cycle Gas Turbine
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
NTC	Net Transfer Capacity
OCGT	Open Cycle Gas Turbine
OSC	Other System Charges
PNs	Physical Notifications
RA	Regulatory Authority
RoCoF	Rate of Change of Frequency
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
TOOT	Taking Out One at a Time
TOD	Technical Offer Data
TSOs	Transmission System Operators
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, we take actions to ensure supply of power and system security to customers across the system in real time. The cost of these actions is known as the imperfection costs and are paid for through the Imperfections Charges. We pay for these costs from the money we get from suppliers through the Imperfections Charges.

The purpose of this submission is to set out the TSO's' proposed values for 2024/25 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 2024 to 30 September 2025. The Imperfections Charge parameters is set before each Tariff Year, which is used to calculate Component CIMP 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 best available data at the point of preparation. Most of the input data for the PLEXOS model was compiled as of March 2024. For the K Factor determination, the input data was taken as of May 2024.

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)**

   The FCIMP mechanism allows for adjustment in situations where the Imperfections Price is significantly less or more than we need to recover the anticipated costs. At the time of writing this submission, we do not propose any change to the Imperfections Charge Factor for 2024/25 Tariff Year.

After we make our submission to the RAs, they assess and make a recommendation to the SEMC who decide on the 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 2024/25

We worked out the anticipated Imperfections Charges Parameters, based on several assumptions and expected conditions for the 2024/25 tariff year period (01/10/2024 to 30/09/2025). The table below shows our forecast for the Imperfection Charges Parameters, with the amounts approved for last year shown alongside for reference.

	TSOs' Submission 2024/25 (€m)	RA Allowed Amount 2023/24 (€m)	Difference (€m)
Anticipated imperfections costs (€m)	658.43	539.98	118.45
K Factor (€m)	-66.41	-91.17	24.76
Anticipated imperfections cost less K Factor adjustment (€m)	592.02	448.81	143.21
Forecast demand (GWh)	38,800	38,950	-150
Imperfections Price (PIMP)(€/MWh)	15.26	11.52	3.74
Imperfections Charge Factor (FCIMP)	1.00	1.00	1.00

Table 1 TSOs' Submission of Anticipated Imperfections Charges Parameters

1.3. Main drivers in 2024/25 anticipated Imperfections Charges Parameters

The forecasted imperfection cost for 2024/25 is €658.43m. This is an increase of €118.45m compared to the €539.98m approved by the RAs in the preceding Tariff Year.

The bulk of this increase is due to the inclusion of €158m for potential payments to participants under the Clean Energy Package Article 13(7), as discussed further at Section 4.3.

Excluding the provision for Clean Energy Package Article 13(7) (CEP), we forecast a spend of €500m for the 2024/25 tariff year. This estimated cost aligns with recent trends as shown in below graph.

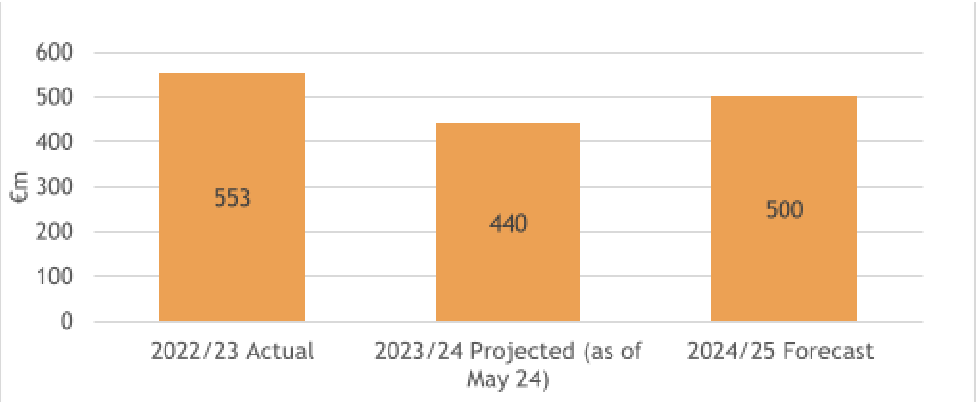

Figure 1 Benchmark of 24/25 Forecast Submission (excluding provision for CEP Article 13(7)) with Recent Costs

Based on our Plexos model, we have identified the following drivers that are predicting an increase in costs:

- Transmission outages: Outages by their nature reduce the flexibility of the system and can lead to higher costs. There are many significant outages planned in 24/25.

- Increased renewable capacity: While our model shows that increasing renewable capacity leads to lower overall system generation production costs, it tends to elevate imperfections costs. This is because the unconstrained model uses this lower-cost energy as much as possible, pushing more expensive thermal generation out of the unconstrained model merit order. The constrained model still needs to run specific generators, that may have been out of merit in the unconstrained model, due to system security/ operational constraints.
- Increased interconnector capacity: While our model shows that increasing interconnector capacity leads to lower overall system generation production costs, it tends to elevate imperfections costs. The model shows that adding in the third interconnector decreases generation costs for both the unconstrained and constrained model. While the constrained model costs reduce, they do not reduce to the same extent as the reduction in unconstrained Model costs. The reason for this increase is a similar concept to that of the increased renewable levels; increased interconnector imports tends to increase imperfection costs as the unconstrained model uses this lower-cost energy as much as possible, pushing more expensive thermal generation out of the unconstrained model merit order. The constrained model still needs to run specific generators, that may have been out of merit in the unconstrained model, due to system security/ operational constraints.

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

- Wholesale fuel and carbon prices: Lower fuel and carbon prices would be expected to reduce overall expenses, especially for fossil fuel-based power generation.
- Generator outages: the model indicates that outages forecast for 24/25 are less costly than those of recent past.

2. Introduction

2.1. Purpose of this report

The purpose of this report is to fulfil the obligation 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 (Ref: Section F.12.1 Part B). The relevant sections of the Trading and Settlement Code are shown in Appendix 1.

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 01/10/2024 to 30/09/2025, referred to as the Tariff Year 2024/25. 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

Constraint costs are the largest portion of imperfections costs. The TSOs, in ensuring continuity of supply and the security of the system in real time, must dispatch some generators differently from the output levels indicated by the market unconstrained schedule. 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 are associated 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 levels of output so that there is spare generation capacity available (known as reserve) which can quickly respond during tripping events and tight margins scenarios. 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 prevent equipment overloading, voltages going outside limits or system instability. 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[1]);
- 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.
Other Dispatch Balancing Costs	
CUNIMB	Uninstructed Imbalance Charges: 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	

[1] 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.

CFC	**Component** Fixed Cost Payment or Charge: 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

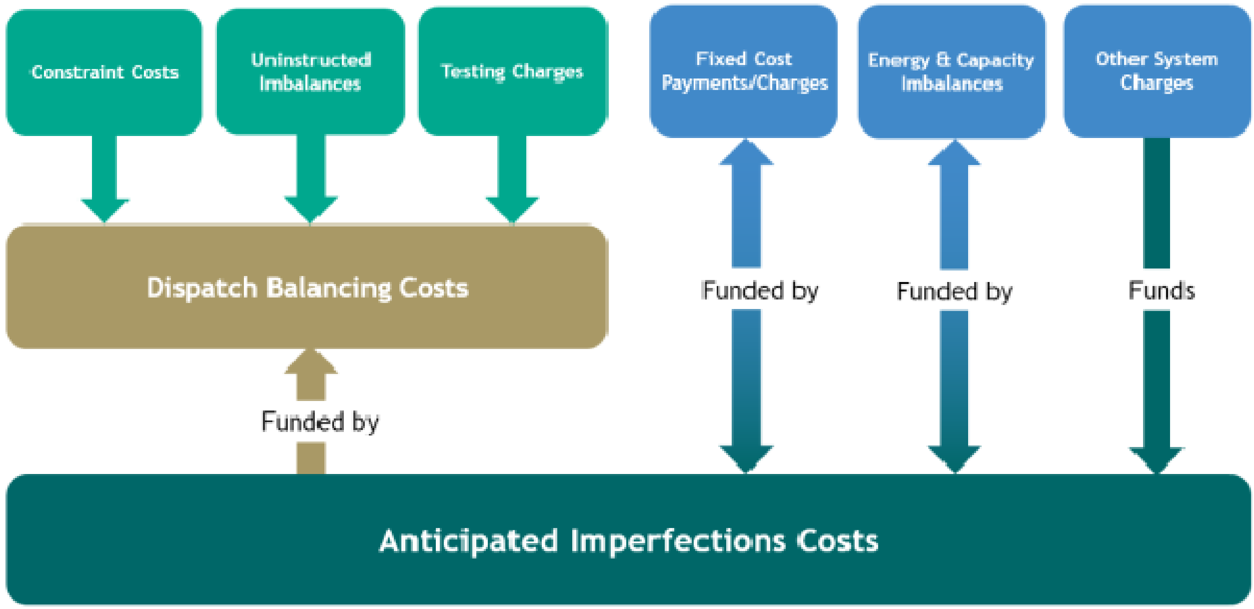

Figure 2 Relationship between Constraint Costs, Dispatch Balancing Costs and Imperfections Costs

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

Supplementary Model

This was used to forecast factors affecting constraints that could not be accurately modelled in PLEXOS. 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 2024/25 Forecast are like those used in previous years. As part of our imperfections work, we also run a Backcast Model. The Backcast process starts after the last full tariff year has completed. We then take the original forecast model for that year as a base, and update the assumptions that were used, with actual data for this period. As the Backcast outputs can be measured against actual data, it offers validation that a forecast model cannot, and provides insight which can improve future forecasts. All historic Backcast Reports are published on the SEMC website.

3.2. PLEXOS Forecast Model

PLEXOS is a model that 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 2024/25 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; 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 not represented 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.

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.

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.

A further calculation was run to account for simple price offers, 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:

- Interconnector Counter Trades;
- Pump Storage Running;
- Constrained Wind;
- Energy Imports for Units in System Services modes.

The forecast of these costs is mainly based on historic data. Full details of these costs and how they are forecast is outlined in Section 4.2.

3.4. Forecast Model Limitations

PLEXOS, like all models, will never fully reflect operational reality and cannot be used to produce an estimate for any one specific day. The model is set up for a 12-month study. This means it is important to consider all results according to this timeframe, rather than for specific months or periods of the year in isolation. The forecasting of imperfections is a complex study as the actual spend on imperfections has many interacting variables.

3.4.1. Risk-factors in Forecast

Several risk-factors should be considered when assessing the anticipated imperfections costs for 2024/25. 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 2024. 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 28, dated 18/08/2023). 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).

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 Balancing Market Principles Code of Practice (BMPCOP) 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 spend.

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. Forced transmission outages are not modelled in PLEXOS and no explicit provision has been included in PLEXOS due to the unpredictable nature of such outages.

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. For example, for providing extra reserve.

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.

4. Forecast Constraint Costs

This section sets out our forecast of imperfections costs for the tariff year 2024/25. Our forecast of 2024/25 Imperfections Costs alongside values for the 22/23 Backcast is shown in Table 3.

Note: In previous years, we had compared the values for the upcoming forecast to the values for the previous year's forecast. As described in Section 4.1 below, we have now moved to using a Backcast model as our base, rather than an older forecast model. As a result, it is more meaningful to compare the upcoming forecast to the backcast values. For completeness we have published the comparison of 24/25FC values with 23/24FC values in the Appendix.

Component	2024/25 Forecast (€m)	2022/23 Backcast (€m)	Difference(€m) FC - BC
PLEXOS model	448.71	468.60	-19.89
Supplementary model	51.72	67.38	-15.67
CEP Article 13(7): 01 Jan 20 to 30 Sept 25	158.00	0.00	158.00
TOTAL	658.43	535.98	122.45

Table 3 2024/25 Imperfections Forecast

The following sections detail the PLEXOS and supplementary forecast models.

4.1. PLEXOS results

The 2024/25FC Model was developed using the 2022/23 Backcast Model as its starting point. This is a new approach and further detail is provided below.

2022/23 Backcast Model

The 2022/23 Backcast Model uses various inputs based on actual data for the period 2022/23, resulting in an ex-post adjusted forecast known as the '2022/23 backcast". Detailed information about the 2022/23 Backcast Model, including its description and results, can be found in the report submitted to the RAs accompanying this forecast submission.

Using the 22/23 backcast model as a starting point serves as a validated reference point, as the total backcast costs for 2022/23 fall within the general range of the of the actual costs [3%] for that year. We then incorporated anticipated changes for 2024/25 into this base model to assess their impact.

Historically, we used the previous year's forecast model as a base for the upcoming forecast. However, for the 2023/24 forecast, we chose to use the Backcast model instead. This decision was driven by the Backcast model's validation and the ability to layer changes onto a known starting point. Also, the recent backcast is likely to have more data in common with the upcoming forecast than the previous forecast.

A summary of the 2022/23 actual costs, the 2022/23 backcast model costs, projected 2023/24 Costs (estimate as of May 24) and 2024/25 Forecast Costs are shown in *Figure 3*.

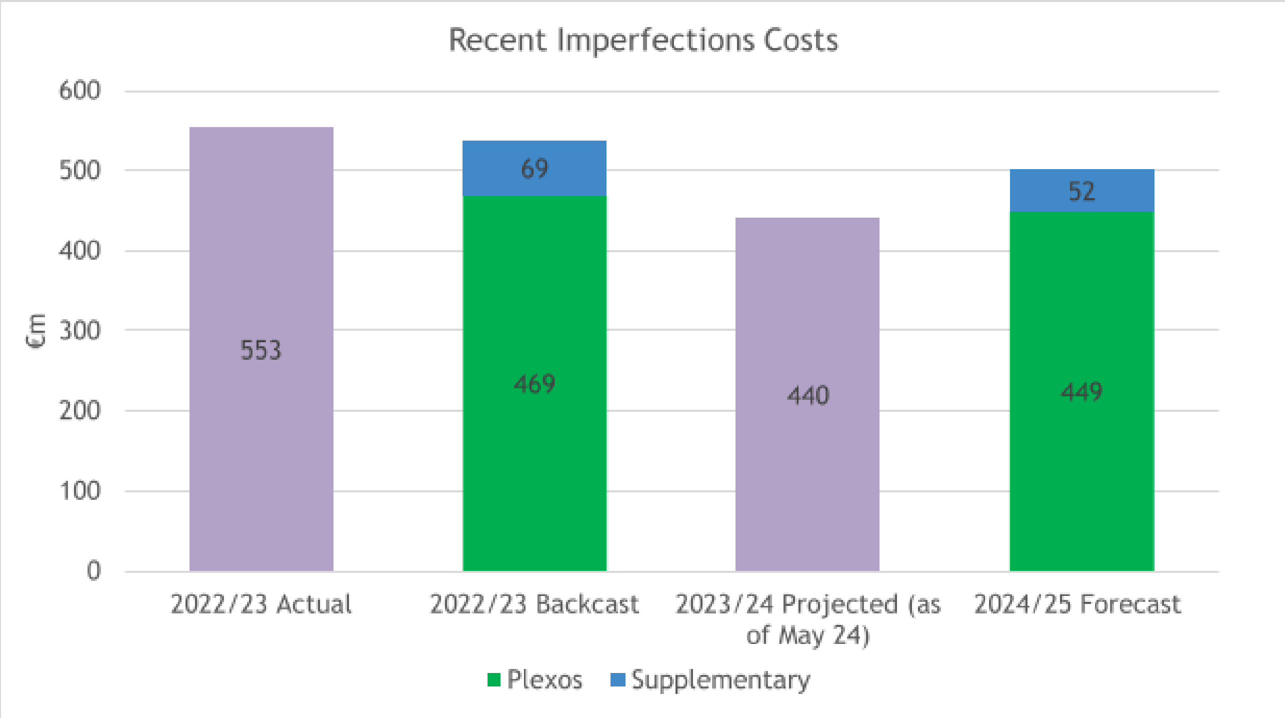

Figure 3 Recent Imperfections Costs (2024/25 Forecast Costs exclude provision for CEP Article 13(7)

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 2024/25 Forecast model and then taking out one input at a time and replacing it with what was in the previous 2022/23 backcast (which are based on actuals). The difference between the two models is shown in Figure 4 below.

For example, the final 24/25FC Plexos Model was €449m. This model was then rerun using fuel/carbon input files as per those of the 22/23BC. The result of this updated model was €582. So the cost impact of the update in the fuel/carbon inputs is €448 - €582 = €-133m

Therefore, the cost impact due to the change in fuel/carbon inputs is €-133 million. The negative sign indicates a decrease in cost.

The cumulative total of all the changes does not sum to €-20m (€449m - €469m, final model cost - starting model cost). The reason being is €-20m is the net result of making all the changes together, at the same time, in the same model, while the values in Figure 4 , are the result of making a change to particular inputs, one at a time, with all other inputs remaining constant. The illustrates the highly complex non-linear nature of the model.

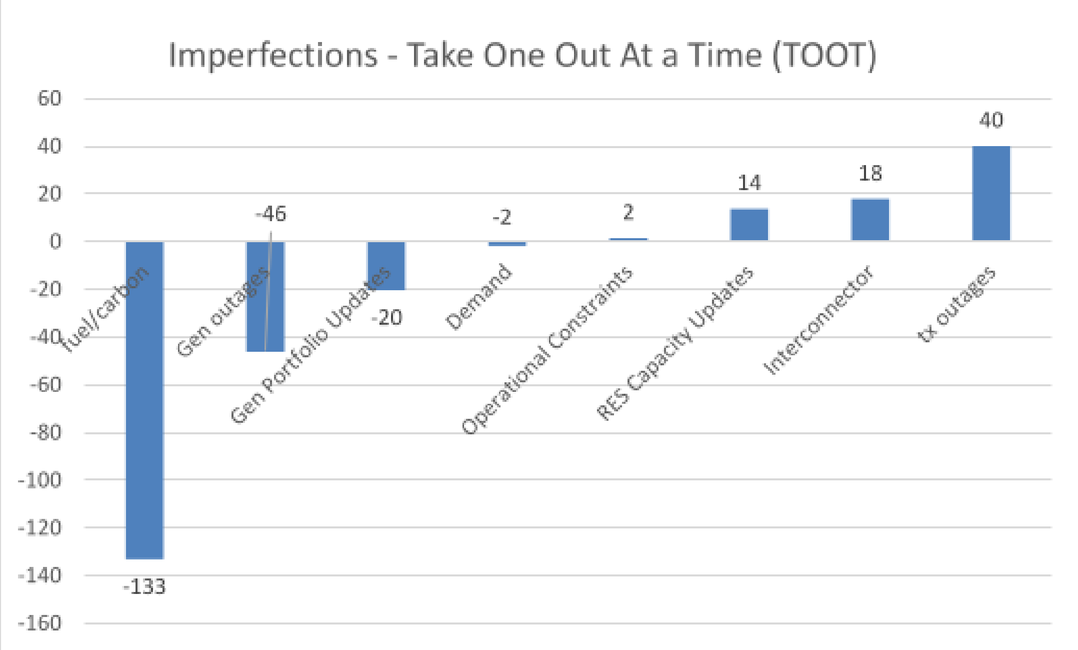

Figure 4 Taking Out One at a Time (TOOT) Analysis on the 2024/25 Forecast Model (€m)

The most significant influences on forecast constraint costs shown in the PLEXOS model, compared to that 2022/23 Backcast, in the PLEXOS model are shown below in Table 4.

Influence	Change to Imperfection cost	Amount in € millions
Fuel price forecasts are significantly lower than those of 2022/23 BC	Reduce costs	€-133m
Forecast generator outages for 2024/25 less onerous than those in 2022/23BC	Reduce costs	€-46m
Generator Portfolio Updates	Reduce costs	€-20m
Update of Demand for 24/25FC from 22/23BC	Reduce costs marginally	€-2m
Operational Constraint updates	increase costs marginally	€2m
RES Capacity Updates	increase costs	€14m
Interconnector	increase costs	€18m
Transmission Outages	increase costs	€40m

Table 4 The drivers on 24/25 Forecast constraint costs compared to the 2022/23 Backcast

There are several factors which may influence the anticipated imperfections costs for the tariff year 2024/25. We describe influencing factors in the following sections.

4.1.1. 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 2022/23 backcast and the 2024/25 forecast. The cost of fuel between these models has decreased significantly. 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.

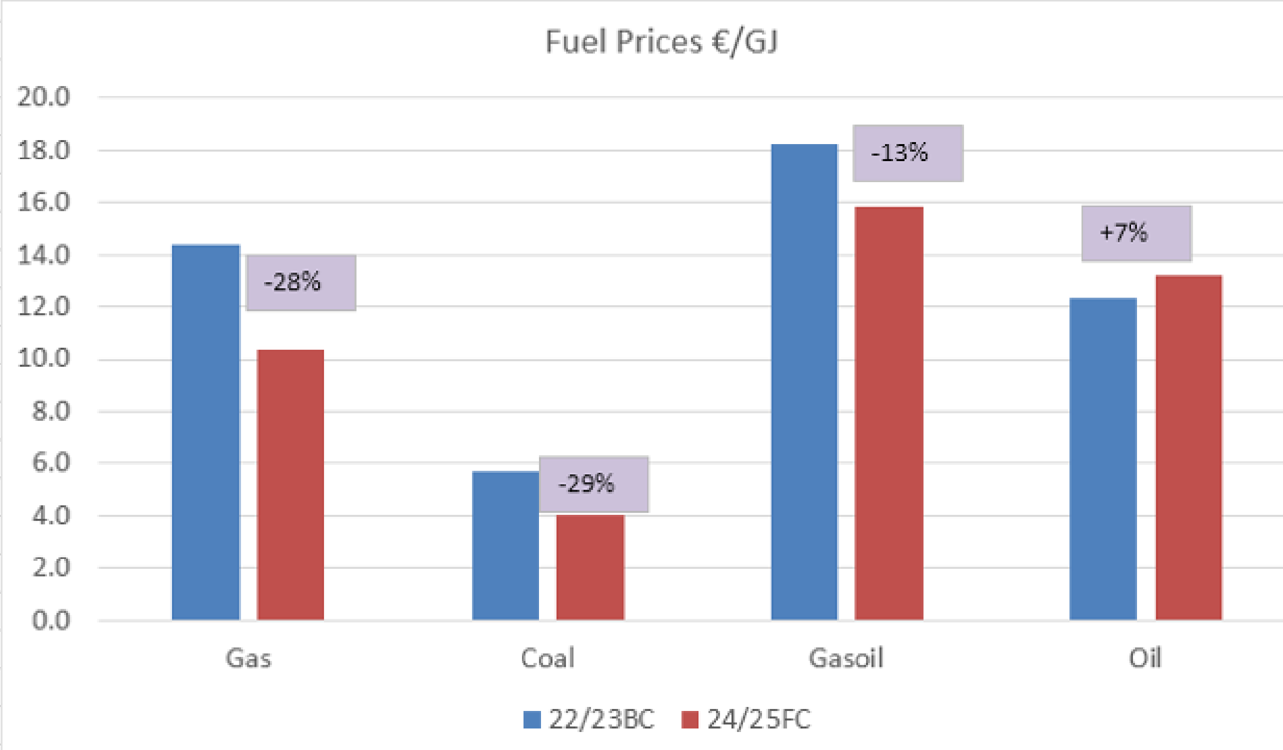

Figure 5 Fuel Cost Changes from 2022/23 Backcast to 2024/25 Forecast

As shown in Figure 6 (below), carbon costs have also decreased. In the same way as wholesale fuel prices, this results in a smaller difference between the constrained and unconstrained model production costs and therefore decreases DBC.

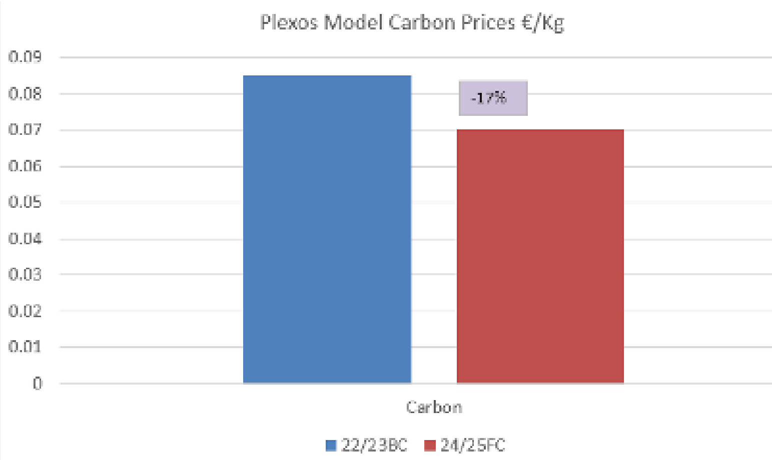

Figure 6 Model Carbon Cost Changes from 2022/23 Backcast to 2024/25 Forecast

4.1.2. Forecast generator outages

Both scheduled and forced generator outages are considered in the PLEXOS model. Scheduled generator outages are relatively fixed and not flexible. Generator scheduled outages are based on the latest available information at time of 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 24/25 Forecast have a lower cost impact on imperfections compared to those in the 22/23 Backcast. The cost impact of generator outages is significantly influenced by other system factors and conditions. An outage can result in either a relatively small or substantial cost impact, depending on various concurrent factors such as wind levels, other units experiencing forced outages, and demand levels. The difference between using the 24/25 Forecast Outages and the 22/23 Backcast/Actual Outages highlights this high level of variability.

4.1.3. Generator Adjustments

In the 2024/25 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. As more flexible generation sources connect to the grid, less flexible units are being phased out. The overall impact of these changes has led to a reduction in costs.

4.1.4. Revised demand

The forecast demand was updated from that in the 22/23 Backcast. Notably, this increase was significant, spanning two years. The forecasted demand was derived by using the 2023 demand data as a base and then applying the median demand growth percentages from the Generation Capacity Statement 2023.

The higher demand led to a slight increase in model generation costs compared to the model with 22/23 Backcast demand. While higher demand typically results in increased unconstrained DBC costs due to more energy being served, it doesn't have as pronounced an impact on constrained model costs. Certain units, such as those needed for reserve or operational constraints, may need to be active regardless of energy demand. Consequently, the higher demand narrows the gap between the unconstrained model and the constrained model, ultimately reducing DBC.

4.1.5. Operational constraints

The best estimate of operational policies / Transmission Constraint Groups (TCGs) 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 2024/25 Forecast Model
System Non-Synchronous Penetration (SNSP)	80%
Inertia	23,000MWs
All-island Minimum Set Requirement	Assume 7 units throughout 2024/25 model

Table 5 Summary of Operational Policies included in 2024/25 Forecast (as of time of model data freeze, March 2024)

The main differences between the 24/25 Forecast and the Backcast is that the 22/23 Backcast had 75% SNSP for full 12 months and the 8 units for Minimum Set Requirement for 7 months. The increase in SNSP levels led to a minor rise in DBC expenses. Conversely, the reduction in Min Sets resulted in a minor cost decrease. Overall, these changes slightly increased imperfection costs compared to the 22/23 Backcast.

4.1.6. Updated Renewable Energy Sources (RES) Capacities

The 24/25 Forecast predicts an increase in renewable generation from wind and solar compared to the 2022/23 Backcast. 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 2024).
- Anticipated connections post the data freeze date, up to 30/09/25, based on build-out rates from the 2023 Generation Capacity Statement.

Increased levels of RES tend to make the difference between the constrained and unconstrained model greater, therefore increasing imperfections costs. The unconstrained model costs are reduced with greater RES levels. However, the constraint models costs do not reduce to the same extent, as certain thermal units, with their associated production costs, must be run to meet system constraints. Therefore, the relative difference between the constrained and unconstrained model increases.

While the model shows that increased levels of RES reduced overall system generation costs, it increases imperfections costs.

4.1.7. Interconnector flows

The forecasted interconnector flows for 2024/25 are based on fixed flows derived from a historic profile.

The profile for the demand and wind availability is also based on the same historic period, which captures the link between interconnector flows and wind/demand patterns.

The Greenlink interconnector, which is due to connect by October 2024, has been factored into the flows. The flows are distributed across the three interconnectors (Moyle, EWIC, and Greenlink). Allocation is based on the best available information regarding interconnector losses. Historical data reveals periods when the existing interconnectors (Moyle and EWIC) operated at full capacity. The model accounts for these periods and makes allowances for additional capacity (to account for increased flows now that there is a third interconnector).

The model shows that adding in the third interconnector decreases generation costs for both the Unconstrained and Constrained model. While the Constrained model costs reduce, they do not reduce to the same extent as the reduction in Unconstrained Model costs.

Our model indicates that while increased levels of interconnection reduced overall system generation costs, it increases imperfections costs.

4.1.8. Transmission outages

In the 2024/25 tariff year, there is a significant program of outages planned for the transmission system. These outages will lead to an increase in DBC.

Amongst the most prominent of these outages is the refurbishment of critical elements of the 220kV and 400kV network, contributing to an increase in Imperfection Charges. All outages by their nature reduce the flexibility of the system, due to unavailability of transmission plant; however, refurbishment of the 220 kV and 400 kV network can be especially onerous, due to the impact on bulk power flows. The outage requirements for the 2024/25 are based on the best available information, as of March 2024. The TSOs have carried out a desktop exercise of the indicative transmission outages, scheduled to take place during the 2024/25 tariff year and have included the relevant outages from a DBC perspective in PLEXOS.

4.2. Supplementary Modelling Results

The supplementary model costs for the tariff year 2024/25 is €51.72m. This represents a decrease of €15.67 from the 2022/23 Backcast. The results of model costs and supplementary costs for 2024/25 are summarised, as compared to the 2022/23 Backcast, in the table below. For completeness a comparison of the 24/25FC costs compared to the 23/24FC costs is presented in the Appendix.

Description	2024/25 Forecast (€m)	2022/23 Backcast (€m)	Difference (€m)
PLEXOS Model	448.71	468.60	-19.89
Additional PREMIUM and DISCOUNT impact	1.46	9.70	-8.24
Interconnector Counter Trades	6.90	8.74	-1.84
Pump Storage Running	17.98	23.95	-5.96
Constrained Wind	23.02	22.64	0.37
Payment for energy imports for units in system services modes	2.36	2.36	0.00
Supplementary Model Total	51.72	67.38	-15.67
CEP Article 13(7): 01 Jan 20 to 30 Sept 25	158.00	0	+158.00
Total	658.43	535.98	122.44

Table 6 Summary of 24/25FC Supplementary Costs compared to 22/23 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, an additional provision of €1.46m has been calculated, within supplementary modelling, for the entire 2024/25 tariff year. This is needed to capture the costs not included within the PLEXOS model. This calculation is based on actual imbalance prices, for the period Oct 22 to Sept 23.

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 2022/23 Forecast is a decrease in the generator offer prices (which is linked to wholesale fuel prices).

4.2.2. System operator interconnector countertrading

For the 2024/25 forecast, an allowance of €6.9m for countertrading has been requested. This allowance has been based on actual cost of countertrades to imperfections in the last 12 months.

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 €17.98m 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.

4.2.4. Constrained wind/ 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 €23.02m within the supplementary modelling. This figure is based on the actual CDISCOUNT that wind/solar participants received in the last 12 months up to 31/04/2024.

4.2.5. Payment for 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 redispatched 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 01 March 2024 indicates an expected annual imperfection cost due to 'Mod 13_19: Payment for Energy Consumption' of €2.36m.

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).

4.2.6. Items included in 23/24FC but not included in 24/25FC

<u>DSU Energy Payments: Modification_02_23</u>
The 23/24 Forecast included a provision of €56 million for DSU Energy Payments. However, this provision has been removed due to ongoing consultations in the area, and the costs associated with this change remain uncertain.

<u>Transmission Outages</u>
In the 23/24 Forecast, there was a provision of €13 million for Transmission Outages in the Supplementary Model. However, since we have now incorporated representative planned outages in the PLEXOS model, this supplementary provision has been removed for the current forecast.

4.3. Clean Energy Package Article 13(7)

We seek a provision of €158m 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[2] .

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 2025, up to market price level.
- Any interest, finance and implementation costs, as well as any amounts that may be recovered from intermediaries, have not been included.

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 2024/25 tariff is made up of two elements:

Description	€m
Actual Y-1 Actual K Factor - 2022/23 K is an Under recovery	(21.59)
Estimate within Year K Factor - 2023/24 K Factor forecast Over Recovery	88
Total Forecast Imperfections K Factor for inclusion in the 2024/25 tariffs (net Over Recovery)	**66.41**

For this period this is a **net Over Recovery of €66.41m** and thus will be **deducted** from the imperfections forecast for 2024/25.

5.1. Actual Y-1 K Factor 2022/23

There was a cash over recovery of €238.8m in 2022/23 which included a previous under recovery forecast position of €140.36m (Ref. SEM-22-045) K Factor as built into the tariffs. Subtracting this K Factor from previous years gives an actual K Factor over recovery of €98.4m arising for the 2022/23 year. However, in calculating the 2023/24 tariff, there was an estimated €120m under-recovery for 2022/23 included (ref. SEM-23-067). Taking this figure into account results in an **outturn under recovery of €21.6m** for tariff year 2022/23. This under recovery will be added to the imperfections forecast revenue.

5.2. Estimate within Year K Factor 2023/24

The Estimated within year (Y) K Factor (2023/2024) is a forecast of the financial position, as reflected in the accounts, as at the end of September 2024. 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.

[2] High Court [2023] IEHC 620: https://www.courts.ie/acc/alfresco/33acac75-8f1f-4c5e-8078-7303630c4ff7/2023_IEHC_620.pdf/pdf#view=fitH

There are two main factors influencing the within year forecast K factor for 2023/2024 - that is the estimated outturn expenditure against forecast and the estimated outturn revenue against forecast.

Estimated Outturn Expenditure - €439.5m [Original - Expected Outturn Spend, €539m - €439.5m = €100.48m over recovery)

Estimated Outturn Revenue - €436.33m [Original + 23/24 k factor - Expected Outturn Revenue, €539m - €91.17m - €436.33m = €12.48m under recovery)

Considering the above 2 factors, we estimate a potential over recovery in 2023/2024 of **€88m** (€100.48m - €12.48m)

The reason for the difference in "Within Year K factor 23/24" to that estimated in March for the 23/24 Mid-Year Report (€106.9m = €115.03m - €8.13m) is we anticipate increased spend during the summer period i.e. €18.9m (€106.9m - €88m). This is due to a Must Run Operational Constraint of 5 units in the Dublin area associated with transmission outages. The projected Imperfections spend to end of Tariff Year has been revised upwards to take account of this operational constraint.

Resettlement

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

Estimated outturn 2023/24 = (€66.41m+€0) = **€66.41m over recovery**

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 2024 to 30 September 2025.

Given the extent of total DBC, and in the context of increased unpredictability and volatility seen under the revised market arrangements, 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, then a 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.

In the 2022/23 Imperfections Decision Paper (SEM-22-45), the SEMC decided that "*The RAs will liaise with the TSOs to develop a biannual review*[3] *of the costs covered by the Imperfections Charge. Therefore, it would be appropriate to put in place a biannual review to build on the TSOs' Quarterly Imperfections Costs Reports and the calculations the TSOs currently use to determine the within-year K-factor. The biannual review would aim to provide a comprehensive estimate of whether any given Tariff Year is likely to result in an Imperfections Charge over or under-recovery*". The 2023/24 Mid-Year Report prepared by the TSOs is published on the EirGrid/SONI/SEMO websites.

[3] The title "biannual review" is now referred to as "Mid-Year Report" to reflect the intention that it is produced approximately at the mid-point (after 5 months of data) of the Tariff Year.

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: (a) The Imperfections Price (PIMPy) in €/MWh for Year, y; and (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 01/10/2024 to 30/09/2025
Data freeze	Most of the input data for the PLEXOS model was frozen at the end of March 2024 For the K Factor determination, the input data was taken as of May 2024
Generation dispatch	Two hourly generation schedules are examined: • one schedule to represent the dispatch quantities (constrained) • 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 by using the 2023 demand data as a base and then applying the median demand growth percentages from the Generation Capacity Statement 2023-2032. 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 Generation Capacity Statement 2023-2032 and REMIT data
Fuel and carbon prices	Fuel/carbon prices for 2024/25 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. 1. Fuel/carbon cost (€/GJ) 2. Piecewise linear heat rates (GJ/MWh) 3. No-Load rate (GJ/h)

Feature	Assumption
	4. Variable Operation and Maintenance Costs (€/MWh) 5. Gas Transportation Charges (GTC) (€/GJ) for gas units 6. Start energies (GJ)
Generation constraints (TOD)	Based on the data Technical Offer Data (TOD) in the SEM, the following technical characteristics are assumed: 1. Maximum Capacity 2. Minimum Stable Generation 3. Minimum up/down times 4. Ramp up/down limits 5. Cooling Boundary Times
Generator scheduled outages	2024 and 2025 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 All-Island Generation Capacity Statement 2023-2032.
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 derived 2022/23 historic flows with adjustment to consider the additional interconnector capacity available with Greenlink
Operational Pathways to 2030 milestones	Operational Constraints were assumed based on the latest available information as of the data freeze. System Non-Synchronous Penetration (SNSP) is set at 80% in the constrained PLEXOS model from Oct 2024. During the year, it is assumed that: • the minimum number of sets is 7 sets, • 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 300 MW S-N.
Forced transmission network outages	Forced transmission network outages have not been 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.

9. Appendix 3: 23/24 Forecast Costs compared to 23/24 Forecast Costs

Component	2024/25 Forecast (€m)	2023/24 Forecast (€m)	Difference(€m)
PLEXOS model	448.71	407.24	41.47
Supplementary model	51.72	205.99	-154.27
CEP Article13(7): 01 Jan 20 to 30 Sept 25	158.00		158.00
TOTAL	658.43	613.23	45.20

Table 8 23/24FC Headline forecast costs compared to 23/24FC forecast costs

Description	2024/25 Forecast (€m)	2022/23 Forecast (€m)	Difference (€m)
PLEXOS Model	448.71	407.24	41.47
Additional PREMIUM and DISCOUNT impact	1.46	58.52	-57.06
Interconnector Counter Trades	6.90	20.61	-13.71
Pump Storage Running	17.98	24.79	-6.81
Constrained Wind	23.02	26.37	-3.35
Transmission Outages	0.00	13.00	-13.00
DSU Energy Payments	0.00	56.00	-56.00
Payment for energy imports for units in system services modes	2.35	6.70	-4.35
Supplementary Model Total	51.72	205.99	-154.27
CEP Article 13(7): 01 Jan 20 to 30 Sept 25	158	0	158.00
TOTAL	658.43	613.23	45.20

Table 9 23/24 Forecast Supplementary Costs compared to 23/24 Forecast costs