2022/23 Imperfections

Outturn Report

31 May 2024

EirGrid SONI

Contents

Revision History		
Revision	Date	Description
R0	31/05/24	Issued to RAs
R1		
R2		

1. Executive Summary

This report to the Commission for Regulation of Utilities (CRU) and the Northern Ireland Authority for Utility Regulator (UR), collectively known as the Regulatory Authorities (RAs), has been prepared by EirGrid and SONI, in their roles as the TSOs for Ireland and Northern Ireland respectively, concerning the 2022/23 Imperfection Costs Backcast. This report covers the period from 01/10/2022 to 30/09/2023 inclusive, referred to as Tariff Year 2022/23.

Imperfections costs are an inherent feature of the SEM design and arise due to the differences between the ex-ante market schedule and the real-time dispatch. These costs are levied on suppliers through the Imperfections Charge.

The TSOs submitted a 2022/23 Forecast to the RAs on 31 May 2022. Using the submitted forecast as a base, the TSOs then updated many inputs based on actual data for this period, to create an ex-post adjusted forecast, the "backcast". A summary comparison of the 2022/23 forecast (Submitted and Allowed), the 2022/23 backcast, and the 2022/23 actual costs are shown in Figure 1 below.

The current resettled actual costs for the 2022/23 year are €553m (shown in green in Figure 1), and the total backcast cost is €536m. The 2022/23 backcast cost is €17m (-3%) lower than the 2022/23 actual cost. This variance is likely due to limitations in modelling such as simplifications/ approximations in representing reality and inherent complexity of the system being modelled.
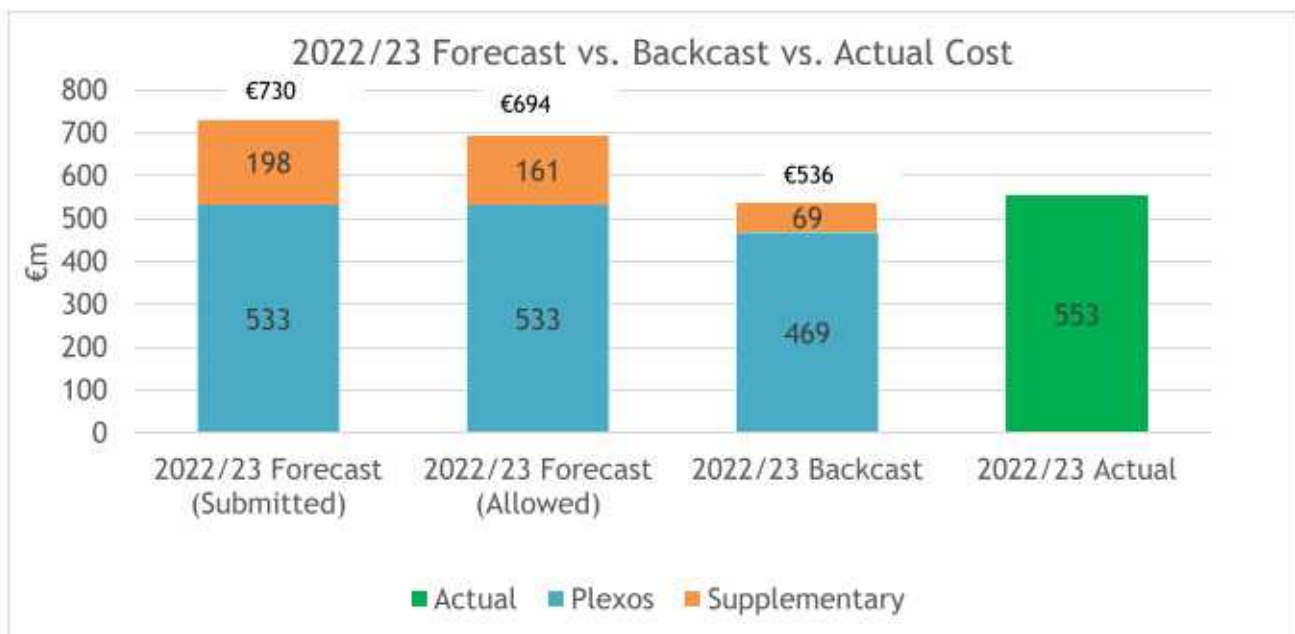

Figure 1 2022/23 Forecast vs. Backcast vs. Actual cost comparison

2. PLEXOS Comparison

The PLEXOS model component of the backcast for 2022/23 was found to be €469m. This is a decrease from the submitted PLEXOS forecast cost of €533m. As shown in Figure 2, updating the 2022/23 Forecast PLEXOS model with actual data led to a decrease of €64m.

Figure 2 PLEXOS change when updated with actual 2022/23 data

Figure 3 shows the drivers which contribute to this decrease of €64m.

The costs within the graph have been determined by using the final backcast model (i.e., based on actual outturn data), and then removing each input, on its own, from that model and replacing it with the inputs used in the original 22/23 forecast. This is known as a TOOT analysis (Take One Out at a Time). This allows for a comparative approach to be taken to see the impact of an input on the same model. The cumulative total of all the changes in Figure 3 does not add up to €-64m. The reason being is €-64m is the result of making all the changes together, at the same time, in the same model, while the values in Figure 3, are the result of making a change to particular inputs, one at a time, with all other inputs remaining constant.
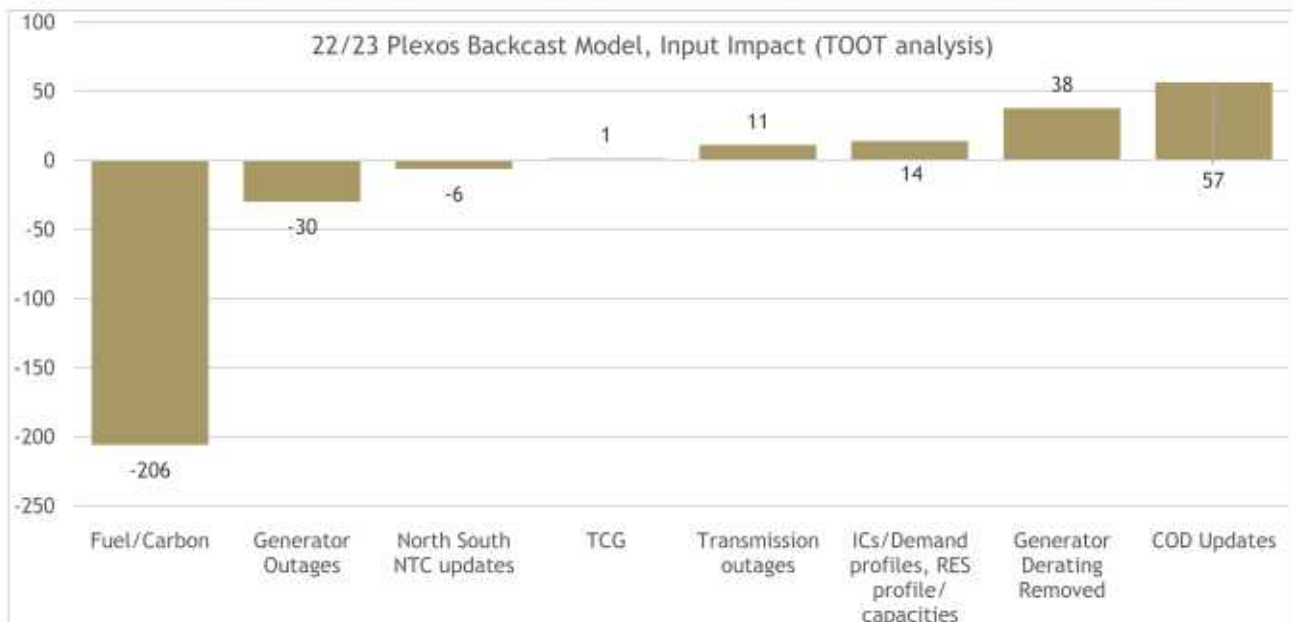

Figure 3 2022/23 Backcast PLEXOS – Input Impact

2.1. Fuel and Carbon Prices

Updating the model for actual fuel/carbon prices decreased model costs by €206m. This was due to significant decrease in all fuel types between the 2022/23 Forecast and 2022/23 Actual fuel prices. See summary of model input prices below:
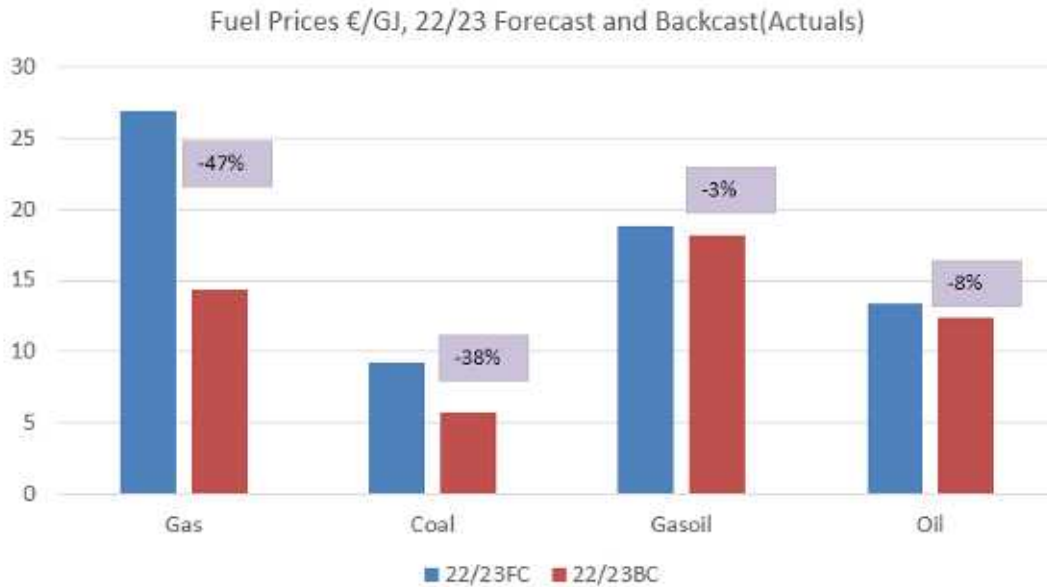

Figure 4 Fuel Prices - 2022/23 Forecast vs 2022/23 Actual Prices

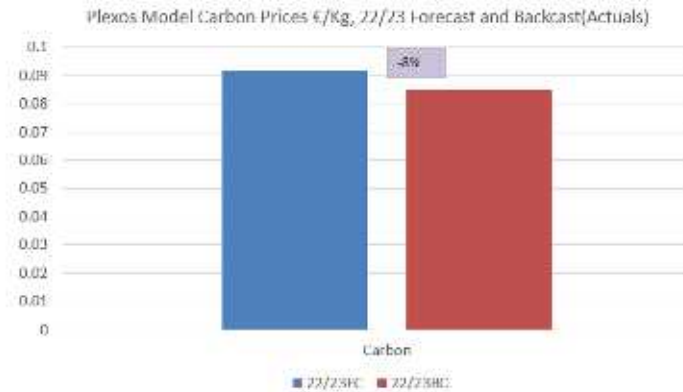There were also decreases in carbon prices, See summary of model price changes below:

Figure 5 2022/23 Carbon Prices - 2022/23 Forecast vs 2022/23 Actual.

2.2. Generator Outages

Generator outages were updated to reflect the actual outages that happened in 2022/23. The model shows that the actual outages in 22/23 were less costly than those assumed in the 2022/23 Forecast. This led to a decrease in the model costs of €30m.

2.3. Network Adjustments

The transmission limits of the Louth-Tandragee tie-line were updated in the 2022/23 Backcast model. In the original 22/23 FC we had flow limits set to "400 MW North to South and 250 MW South to North". For the 22/23 Backcast, these were set to 450 MW North to South and 300 MW South to North. These updates were based on analysis of actual flow data in the 2022/23 year. The changes in the model resulted in an increase in flow capability from North to South. Updating the model with these changes resulted in a decrease in model costs of €6m.

2.4. Transmission Constraint Groups (TCGs)/ Operational Policies

The Operational Policies in the model were updated to align with the latest policies in 2022/23 (which had not been included in the original forecast).

- Forecast had assumed a Minimum conventional set requirement of 8 units, while this was changed to 7 units from 01/06/2023 in the 2022/23 Backcast.
- There was an update of the South Rules, "L01, L02 and HI1" between those assumed in the Forecast and those in the Backcast.

These adjustments led to a slight net increase of €1 million in the model costs compared to the inputs from the 2022/23 Forecast model. However, this change is minor and can thus negligible in the broader imperfections context.

2.5. Transmission Outages

The model was updated to reflect the actual transmission outages that took place in 2022/23. The model indicates that the number of outages impacting imperfection costs was higher than anticipated in the original 2022/23 forecast. These outages increased model costs by €11m.

2.6. Demand, IC Flows & Wind Availability

As there is a link between demand, interconnector flows and wind availabilities, these were analysed together rather than individually. Analysing these inputs together resulted in an increase in model costs of €14m.

The demand in the Backcast is lower than the Forecast. This is likely to be a reason for the increase in costs. The lower demand led to a slight decrease in model generation costs compared to the model with 22/23 Forecast demand. While lower demand typically results in smaller unconstrained DBC costs due to less energy being served, it doesn't have as much 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 lower demand widens the gap between the unconstrained model and the constrained model, ultimately increasing DBC.

2.7. Removal of Derating in Day Ahead market of certain units

In the 22/23 Forecast, the capacity of certain gas units was derated in the Unconstrained Model. Upon analysis of Day Ahead data, it was decided it is more appropriate not to derate these units. Therefore, in the 22/23 Backcast, the same generator capacity value was used in the Unconstrained Model as the Constrained model. This update increased the Plexos costs by €38m.

2.8. Commercial Offer Data (COD)

Commercial offer data for each unit was updated. The updates were based on analysis of historic data including no-load and start-up costs. We removed the impact of fuel/carbon costs as these are analysed separately under the fuel/carbon category. This amounted to an increase in model costs of €57m.

3. Backcast Results Compared to Actuals

This section contains a comparison of the following:

- 2022/23 Forecast Submission & RA Allowance;
- 2022/23 Backcast Model Result;
- 2022/23 Actual Outturn

3.1. 2022/23 Forecast Submission & RA Allowance

For the 2022/23 Tariff Year, the TSOs submitted an Imperfections forecast of €730.45m. This comprised of €532.94m for the PLEXOS model and €197.51m for the supplementary model. Following consultation, the RAs determined a total allowance of €694.17m for the year, deducting elements from the supplementary modelling. These values are represented by the first two bars in Figure 6 below:
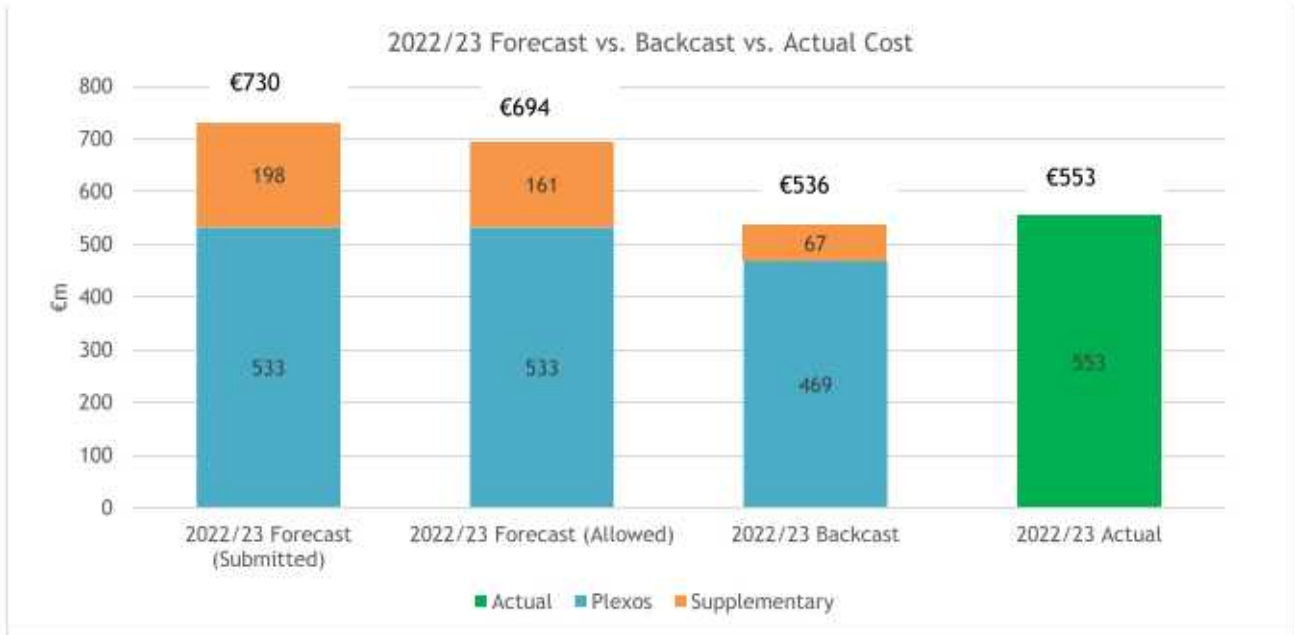
Figure 6 2022/23 Forecast vs. Backcast vs. Actual cost comparison

3.2. 2022/23 Backcast & Actual Outturn

PLEXOS backcast: Figure 6 shows that by updating the original forecast with actual data, the PLEXOS element decreased from €533m to €469m. These changes are detailed in Section 2.

Supplementary backcast: Due to the significant changes in certain inputs, predominantly wholesale fuel costs, it was prudent to recalculate the approved Supplementary Modelling, which was originally approved at €161m. With significant decreases to in fuel prices and therefore the imbalance price, this decreased to €67m. The most significant change is the drop in the Premium/Discount Component from €99m to €10m. The main driver for this decrease is a reduction in the imbalance price, and generator bids.

The main changes in the supplementary modelling are shown in Figure 7 below:

Description	22/23 Submitted (€m)	22/23 Allowed (€m)	22/23 Backcast (€m)
PLEXOS Model	532.94	533	469
Additional PREMIUM and DISCOUNT impact	99	99	10
Interconnector Counter Trades	36	17	9
Pump Storage Running	35	18	24
Constrained Wind	24	24	23
Payment for energy imports for units in system services modes	0	0	2
Block Loading, Capacity Testing, Secondary Fuel testing	4	4	0
Supplementary Model Total	198	161	67
TOTAL	730	694	536
	Actual 2022/23		553
	€m variance		-17
	% variance		-3%

Figure 7 2022/23 Forecast vs. Backcast vs. Actual cost comparison

The current resettled actual costs for the 2022/23 year are €553m (shown in green in Figure 6), and the total backcast cost is €536m. The 2022/23 backcast cost is €17m (3%) lower than the 2022/23 actual cost. This variance is likely due to limitations in modelling such as simplifications/ approximations in representing reality and inherent complexity of the system being modelled.