Forecast Imperfections Revenue Requirement

For Tariff Year 2021/22

Version 2.0
04/06/2021

Executive Summary

This submission represents the Transmission System Operators' (TSOs') forecast of the revenue requirement to be recovered through Imperfections Charges during the 2021/22 tariff year.

The purpose of the Imperfections Charge is to recover the total expected costs associated with managing the transmission system safely and securely, the bulk of which are under the umbrella of Dispatch Balancing Costs. Adjustments for previous years are also considered by the Regulatory Authorities in their final decision on the Imperfections Charge.

The forecast revenue requirement, based on a number of assumptions and expected conditions for the 2021/22 tariff year period (01/10/2021 to 30/09/2022) is €473.09m[1]. This is an increase of €116.42m over the equivalent forecast 2020/21 requirement of €356.67m, of which €301.47m was approved, by the Regulatory Authorities, in their final decision on the Imperfection Charge.

The approach taken in the 2021/22 forecast has been to use a PLEXOS model, which assumes that the Dispatch Balancing costs in SEM are based on the production cost difference between the unconstrained and constrained models. Additional SEM costs, not covered in the PLEXOS model, are captured in supplementary modelling.

The main components of the 2021/22 forecast revenue requirement submission are set out in the table below:

Component	21/22 Forecast (€m)	20/21 Forecast (€m)
PLEXOS Modelling	**291.40**	**265.60**
Supplementary Modelling	**181.69**	**90.07**
Total 2021/22 Forecast Imperfections Revenue Requirement	**473.09**	**356.67**

[1] It is noted however that €124.5m of this forecast pertains to the potential settlement of payments to participants between January 2020 and End September 2021 and that estimated for the period October 2021 to end September 2022 under the implementation of Article 13 of the Regulation (EU) 2019/943.

1. Introduction

This submission to the Commission for Regulation of Utilities (CRU) & the Utility Regulator for Northern Ireland (UR), collectively known as the Regulatory Authorities (RAs), has been prepared by EirGrid and SONI in their roles as the Transmission System Operators (TSOs) for Ireland and Northern Ireland respectively.

The submission reflects the TSOs' forecast of the revenue required from the Imperfections Charge for the 12 month period from 01/10/2021 to 30/09/2022 inclusive, referred to as the tariff year 2021/22.

The primary component of the Imperfections revenue requirement is Dispatch Balancing Costs (DBC). DBC refers to the sum of Constraint Payments, Uninstructed Imbalance Payments and Testing Charges. The Constraint Payments in SEM can be broken down into CPREMIUM, CDISCOUNT, CABBPO, CAOOPO and CCURL. The cost component definitions are provided in Appendix 6. Other elements also contribute in setting the regulated Imperfections Charge including the Imperfections K factor, which adjusts for previous years, as appropriate, and the forecast system demand.

The resulting Imperfections Charge is levied on suppliers, as a per MWh charge on all energy traded through the Single Electricity Market (SEM), by the Market Operators.

This forecast does not include any charges incurred for the holding, or use, of required banking standby facilities, to provide working capital for the TSOs. The costs incurred as a result of holding banking standby facilities are assumed to be recoverable through the TUoS tariff in Ireland and SSS tariff Northern Ireland, under the respective regulatory arrangements pertaining.

The TSOs' forecast for the Imperfections revenue requirement is €473.09m, in nominal terms, for the tariff year 2021/22. A detailed breakdown of the forecast individual components is contained in Section 2.

1.1 Background of the SEM

The wholesale electricity market arrangements for Ireland and Northern Ireland were revised under the I-SEM Project, with the revised SEM arrangements going live on 1 October 2018. The new market arrangements are designed to integrate the all-island electricity market with European electricity markets, enabling the free flow of energy across borders. It consists of a number of markets including:

The Day-Ahead Market (DAM) is a single pan-European energy trading platform in the ex-ante time frame, for scheduling bids and offers and interconnector flows across participating regions of Europe. The DAM involves the implicit allocation of cross-border capacity through a single centralised price coupling algorithm. The algorithm, taking into account the cross-border capacity advised by the TSOs, determines prices and physical positions for all participants in all coupled markets. Since 1st January 2021, BETTA bidding zone borders have been removed from the algorithm and, as a result, the DAM does not calculate the cross-zonal flows between the SEM and BETTA. The SEM is scheduled on an "isolated" basis without consideration of changes in cross-zonal flows in the DAM.

The Intra-Day Market (IDM) allows participants to adjust their physical positions closer to real time. The need to adjust their positions can arise for a number of reasons, including orders failing to clear in the DAM, new information becoming available (e.g. plant shutdowns and changes to forecasts), congestion on interconnectors driving price differentials between zones, and asset less traders wishing to exit their positions. Since 1st January 2021, the Intraday Auctions carried out between the SEM and BETTA are also the only means of scheduling interconnector flows in the markets between the jurisdictions. It does this in a similar way to how it is done for the DAM, where it involves implicit allocation of cross-zonal capacity through a single centralised price coupling algorithm, just considering the IDM order books for the SEM and BETTA markets. The long-term model for a single European trading platform was based on continuous cross border trading. However, since go-live, intraday trading is only continuous within the new SEM (within-zone), where bids and offers are continuously matched on a first-come-first-served basis.

The Balancing Market (BM) determines the imbalance price for settlement of energy balancing actions and any uninstructed deviations from a participant's notified ex-ante position. The BM is different from the other markets in that it reflects actions taken by the TSO to keep the system balanced and secure, for example, any differences between the market schedule and actual system demand, variations in wind forecasting, or following a plant failure. The BM uses a rules based flag-and-tag process to determine the offers and bids that are scheduled due to system and unit constraints. It uses this information to determine the spot price in each 5 minute imbalance pricing period, as the most expensively priced offer or bid that is dispatched for energy balancing, rather than system constraint reasons. The imbalance price for the 30 minute imbalance settlement period is the average of the six imbalance prices.

Participants are responsible for meeting their ex-ante commitments and when they cannot they are financially exposed in the BM. Uninstructed deviations from the schedule are settled at the imbalance settlement price. Instructed deviations from balancing market actions, to increase or decrease output for energy or non-energy reasons (e.g. reserves, voltage, congestion on lines, etc.), are settled at the most beneficial of either the bid/offer price or the imbalance settlement price. If the generating unit is constrained up it will be paid the higher of the imbalance settlement price or offer price, and if the generating unit is constrained down it will pay the lower of the imbalance settlement price or bid price.

1.2 Modelling approach for Tariff Year 2021/22

The revised SEM arrangements have seen an increase in Imperfections Costs. In the new settlement design the imbalance price is one of the major drivers of constraint costs. The imbalance price can be volatile compared to the legacy SEM, with multiple instances of the price being negative when the market is long and the price being very high at times when the market is short and highly constrained. Because the production cost difference between the unconstrained and constrained model does not consider the model price, additional post processing to shadow settlement was conducted outside of the PLEXOS model. The two scenarios which cannot be captured in PLEXOS production cost difference are when the constrained up price is lower than the imbalance price and when the constrained down price is higher than the imbalance price. Another feature of the revised SEM arrangements, which could not be fully captured in PLEXOS, is that generators can submit both complex and simple commercial offer data, in the form of complex incremental/decremental costs, and simple incremental/decremental costs. Additional costs that cannot be modelled are captured in the supplementary modelling.

2. Forecast Constraint Costs

This section sets out the TSOs' forecast constraint costs element of the total Imperfections revenue requirement for the tariff year 2021/22, including the results of the forecast costs from the PLEXOS model, in addition to the supplementary modelling, as outlined in Sections 2.1 and 2.2 respectively. A summary of other components of the Imperfections revenue requirement are outlined in Section 2.3.

2.1 PLEXOS Results

The forecast cost of the constraints modelled using the PLEXOS model for the 2021/22 tariff year is **€291.40m**. For reference the PLEXOS cost for 2020/21 was €265.60m.
The most significant influences on forecast constraint costs, compared to that forecast in 2020/21, in the PLEXOS model are:

- Fuel forecasts, which are significantly higher than those of 2020/21, have increased costs by €99m
- A total increase of 161 MW in wind / PV generation and DSUs contributes to an additional Imperfections cost of €9m
- The retirement of the two peat plants (LR4 and WO4) has increased costs by €9m
- A decrease in the scale of scheduled transmission outages has decreased the PLEXOS model by €23m. Of note, there is a significant reduction in outage days associated with the 400 kV Dunstown – Moneypoint line and the 220 kV Flagford – Louth line.
- Update of Gas Transportation Capacity charges has decreased the PLEXOS model by €22m
- Operational Constraints updates have decreased the model by €9m. Of note, the Tarbert voltage control transmission constraint has been removed due to the upcoming reactor installs providing support in the area.
- Forecast generator outages for 2021/22 has decreased costs by €9m
- Revised interconnector flows and north-south tie-line limits have decreased model costs by €9m. For the interconnector flows, the main change is the time based increase in firm export capacity expected in the 2021/22 year:

Date	Export
Oct 2021	250 MW
Nov 2021 – Mar 2022	160 MW
Apr 2022 – Sept 2022	400 MW

  For the tie-line limits, the model increase, specifically in the North-to-South direction, has allowed a greater flow out of Northern Ireland
- Update of generator Commercial Offer Data has reduced costs by €8m

- Update of model adjustments has reduced the cost by €7m. The majority of this is based on the second 400 kV/220 kV Moneypoint transformer being available, beneficial technical offer data changes, and a slightly higher efficiency value for Turlough Hill based on the latest actual data.
- Inclusion of forecast DS3 / Operational Pathways to 2030 milestones has reduced the cost by €7m. System Non-Synchronous Penetration (SNSP) is set at 75% in the constrained PLEXOS model from Oct 2021. During the year, it is assumed that the minimum number of units is reduced from 8 to 7 and subsequently that the minimum level of inertia is reduced from 23 GWs to 20 GWs.
- Forecast demand has increased, as per the 2021 GCS, which has decreased the PLEXOS model costs by €6m
- Provision of reserve by additional batteries has further reduced costs by €2m. The level of batteries included in last year's model significantly reduced costs, and added reserve to a point nearing saturation. The additional batteries in this year's model have had a lesser impact on reducing costs.

There are a number of factors which may influence the forecast costs, and hence the Imperfections revenue requirement, for the tariff year 2021/22. Influencing factors are described in the following sections.

2.1.1 Fuel Prices/ GTCs

There is an increase in forecast wholesale fuel prices and carbon for 2021/22, Figure 1 outlines the differences in the fuel prices from the 2020/21 forecast to the 2021/22 forecast; this makes the cost of constraining on out of merit generation more expensive and drives a higher production cost in the constrained model. The result is that the disparity between the unconstrained and constrained model production costs increases, and with it the DBC.

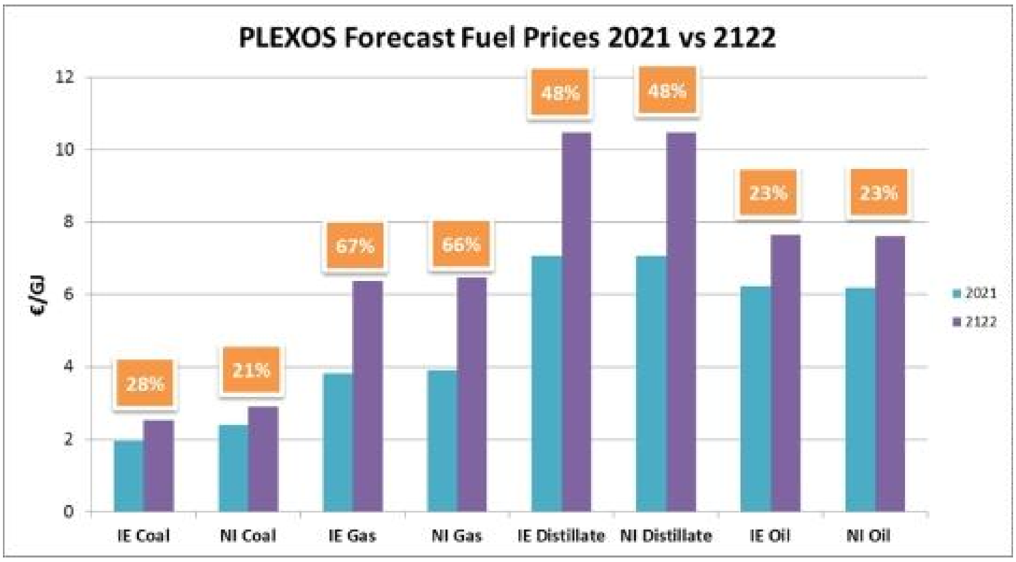

Figure 1: Forecast model fuel price changes from 2020/21 to 2021/22

It has been assumed that nine gas-fired generation units in Ireland and three gas fired generators in Northern Ireland will include the cost of particular gas network capacity products in their generator offers, based on current Gas Transportation Capacity (GTC) charges. This increases the offer price of these units and leads to increased constraints costs, when they are constrained on in dispatch, to meet reserve, transmission or security constraints, on the power system. In general, the GTCs assumed for each unit have been based on analysis of historic generator bids.

2.1.2 Generation Merit Order

Compared to the tariff year 2020/21 forecast, there has been a change in the generation mix available in the market. There is an increase in priority dispatch generation from wind (130MW) and solar (49MW). This has the effect of increasing DBC as the unconstrained model uses this as much as possible, pushing more expensive conventional generation out of the merit order. The constrained model still needs to run specific generators that may have become out of merit due to the increase in priority dispatch generation. The 2021/22 model does not include the recently retired West Offaly and Lough Ree peat units.

2.1.3 Interconnection

Forecast interconnector flows for 2021/22 are based on historic actual interconnector flows, matched with historic actual wind availabilities. As interconnector and wind profiles are so closely linked, the approach of using these two 'already matched' sets will assist in modelling reality. Moyle exports were limited to firm capacities as defined between Mutual Energy and National Grid.

2.1.4 Transmission Outages

The outage requirements for the 2021/22 are based on the best available information, as of April 2021. The outages assumed in the forecast are indicative only and subject to change. 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 programme of outages assumed for the 2021/22 is less onerous compared to that assumed for the 2020/21 forecast. These outages are listed in Appendix 3 of this submission paper.

2.1.5 Model & Operational Constraint Updates

The transmission network has been reviewed to reflect the forecast configuration & operation. 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.

2.1.6 Impact of Storage on Reserve

In order 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. This is one reason why the actual dispatch may deviate from market schedule, which contributes to DBC costs. Large scale batteries to the amount of 160 MW were introduced in the 2020/21 model, and the inclusion of a further 323 MW of storage / batteries in the 2021/22 Forecast further helps reduce this cost, as it is assumed that these units will be available to provide reserve and therefore they replace the reserve previously obtained from thermal units. As highlighted previously, due to the significant amount of reserve available from all sources, the cost benefit of adding additional batteries is decreasing.

2.2 Supplementary Modelling Results

The individual components of supplementary modelling, which take account of specific external factors that cannot be captured in PLEXOS modelling, are outlined and discussed in Appendix 1.

The forecast cost of the constraints modelled by the supplementary modelling for the tariff year 2021/22 is **€181.69m**. This represents an increase of €90.62m from the 2020/21 tariff year.

The largest influences on the changes to supplementary modelling are:

Clean Energy Package: Included in the TSOs' Forecast Imperfections Revenue Requirement for tariff year 2021/22 is a provision of €124.5m for potential payments due to participants under Article 13 of the Regulation (EU) 2019/943. On finalisation of the arrangements, impacted parties may be eligible to be resettled back to 01 Jan 2020. As a result payments related to the period 01 Jan 2020 through to 30 Sep 2022 (almost 3 years) may be incurred in the 2021/22 tariff year. It is noted that the RAs' consultation on same (SEM-21-027) is on-going and no determination has yet been made in this regard. As such the provision is included without prejudice to the final decision.

A summary of some of the assumptions and methodology used in forming the €124.5m provision is outlined below:

- The provision is calculated based on what the potential exposure would be, should constraint and curtailment volumes be required to be compensated, up to their support price level. This analysis assumes that this scenario would apply to both existing priority dispatch units, which would require retrospective compensation since January 2020, and new non-priority dispatch supported renewables.

- Whilst this is without prejudice to any final decision, and recognising that the consultation is ongoing, we believe this is a prudent assumption. Furthermore it should be noted and must be recognised that there is no ability for the TSOs to pay out such compensation should the ultimate decision require it absent its provision in the tariff. Therefore, both to enable any such compensation to be paid should it be necessary to do so, and also so as to not effectively prejudice and pre-determine the consultation itself through this tariff setting process it is correct, and proper, that a provision be placed within the tariff forecast, and tariff, for the payment of such compensation.

- An as-close-to-accurate-as-possible analysis of the cost of compensation, which would arise over the 2020 year was carried out, by using the actual settlement volumes for constraint and curtailment of wind and solar PV, in each half hour, and the actual Day-ahead Market and Imbalance Prices, with estimated representations of renewable support prices. These volumes are based on the most recent settlement run, which varies depending on the date in question. All volumes were taken to be dispatch down from the market position, as there is currently no compensation for constraint or curtailment below availability, which is not reflected in market trades. Only delivered dispatch down volumes were considered, also non-delivered volumes were removed. Separate volumes were considered for Ireland (IE) and Northern Ireland (NI), see further below for information on different compensation approaches. The costs are calculated for each individual half hour period based on this data, which is then summated over the annual level, or other levels required;

- For constraints, only firm volumes were considered, based on the current market design, that only firm constraints are eligible for compensation (i.e. eligible to retain their ex-ante revenue). If this were to change, e.g. if participants were to make an argument that they should be compensated for non-firm volumes, or that they should be considered as firm where they are currently considered non-firm, then this would increase the exposure and the analysis performed for calculating this provision would need to be repeated, with different volumes. Currently, firmness is not a consideration for curtailment, i.e. the same settlement treatment is applied to curtailed volumes below market position, regardless of whether the volume is firm. However, the recent SEM Committee paper on Article 13 mentions firmness when considering compensation to the market price for curtailment. Therefore, separate scenarios are considered in the calculations to cover if all curtailment volumes need to be compensated, or if only firm curtailment volumes need to be compensated;

- Based on this estimated analysis of 2020 costs, forecasts were made of the potential costs arising in the imperfections years 2020-2021 and 2021-2022 – all periods since 2020 are included, rather than just the current forecast year, because this is compensation which would not have been paid, and therefore this is an estimate of the risk of exposure, should compensation be required to be retroactively given;

- For simplification, the same costs as calculated for the year 2020 were taken to apply for the imperfections forecast years 2020-2021 and 2021-2022. This is based on the dispatch down levels in this year's forecast PLEXOS model being in the same region as the recent actual dispatch down values (for example, due to SNSP levels increasing);

- To try and increase the accuracy, different approaches for calculating the support price level to be compensated were taken for IE volumes and NI volumes:
  - For IE volumes, only REFIT was assumed; a small amount of RESS supported units may be joining within the current forecast year, but this would not be expected to make much of a difference to the estimate, given their relative size, the later dates within the year that they would be joining, and the level of the RESS1 average prices. A REFIT support price was estimated for the years 2020-2022 based on public sources[2] outlining the methodology where they have a base price, have a balancing price element added to it, and increases to each of these considering average CPI. An average of the estimated prices over the three years was taken for simplification so that only one price is used across all periods calculated. The reference price for this REFIT support price is compared against a blended average made up of 80% of the day-ahead market price and 20% of the imbalance price, assumed to apply evenly, although smaller wind is supposed to have a different rate, based on the following

[2] e.g. https://assets.gov.ie/76538/5128ec59-0867-4fe3-823b-cd34b7639e98.pdf

https://www.cru.ie/wp-content/uploads/2020/01/CRU2013-Decision-Arrangements-for-the-Calculation-of-the-Public-Service-Obligation-Levy-post-I-SEM-Implementation.pdf. The cost of support is calculated based on the following formula: Max (Support Price – Blended Reference Price, 0) x Volume;
    - For NI volumes, a support price for the NIROCs was estimated, based on analysis of previous years' reference prices[3], specifically focusing on the wind reference prices for simplification). Similarly, a price was estimated for each of the years 2020-2022, and an average of these three estimated prices was used across all periods calculated. This is a top-up payment mechanism, rather than a Feed In Tariff, and therefore the cost of the support is a simple multiplication of Volume x Support Price.

- The costs for compensation were calculated in the following three categories, being those where compensation is not currently active:
    - Compensation for firm constrained volumes from the market price level to the support price level;
    - Compensation for (firm or all) curtailed volumes to the market price level. This cost is calculated as a simple Day-ahead Market Price x Volume (this is the smallest element of compensation calculated, may not need to feature in future forecasts but included for now as it would at least be a reimbursement required for 2020-2021);
    - Compensation for (firm or all) curtailed volumes from the market price level to the support price level.

Imbalance Price data taken from internal databases and SEMO website reports (same data source, includes backup prices). Where an imbalance price or backup price was not available, the day-ahead price was the only price used as a reference price for REFIT. Day-ahead market price data taken from SEMOpx reports on its website[4].

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. TSOs have to pay a generator the better 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. The majority of this extra cost, as described in Section 1.2, is taken into account using the production cost based PLEXOS modelling, however an additional provision of €23.21m has been calculated, within supplementary modelling, for the entire 2021/22 tariff year, to capture the costs not included within the PLEXOS model. This calculation is based on actual imbalance prices from the last 12 months.

This impact was calculated by applying the settlement calculation for the two highest settlement cost components CPREMIUMS and CDISCOUNTS. The calculation involved applying the CPREMIUM and CDISCOUNT market formulae to the dispatch volume change between the unconstrained and constrained models. A further calculation was

[3] https://www.ofgem.gov.uk/system/files/docs/2020/05/ro_annual_report_2018-19_v1.1.pdf
[4] https://www.semopx.com/documents/general-publications/lookback_mkt.xlsx

run to account for simple price offers, based on the proportion of time they had been settled on these, in the last 12 months.

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 TSOs to pump storage units. Another considerable difference is the offer prices associated with pump storage units in the old market compared to the revised market arrangements. Pump storage units in the old market were bidding in with a price of 0 €/MWh and were not paid for non-energy actions, whilst under the revised market arrangements their bid offers are considerably higher. PLEXOS cannot capture the pump storage unit offer prices, thus a provision of €15.58 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.

Constrained Wind: Wind 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, the provision of €5.72m is included within supplementary modelling. This figure is based on the actual CDISCOUNTS wind participants received in the last 12 months up to 20/03/2021. This cost is separate to the additional costs associated with the Clean Energy Package as detailed previously.

Block Loading: The UUC market schedule assumes that, when synchronising, a generator can reach minimum load in 15 minutes. In practice, it can take significantly longer, particularly for cold units. In actual dispatch therefore, it will be necessary to synchronise such units earlier than in the unconstrained market schedule, resulting in out-of-merit running and hence constraint costs. A small provision of €0.09m is included to cater for the constraints costs arising from out-of-merit running due to the simplification of block loading in the market model.

Although a number of other market modelling assumptions such as the single ramp rate and forbidden zones diverge from reality, it is assumed that the constraint costs arising from these assumptions will balance out over the course of the tariff year and therefore no allowance for them has been included in the 2021/22 submission.

Capacity Testing for System Security & Performance Monitoring: In the interests of maintaining system security, it is considered prudent operational practice to verify the declared availability of generators, in accordance with the monitoring and testing provisions of the Grid Codes. This ensures that the TSOs are using the most accurate information possible and allows generators to identify any problems in a timely manner.

There will be instances of out-of-merit generators not being required to run, and testing the capacity of such units from time to time will necessitate constraining them on, resulting in an increase in constraint costs. A provision is included in this submission, calculated based on an estimate of the additional start costs and out-of-merit running costs.

Testing of generators for Grid Code compliance and performance monitoring is also necessary for system security. To date, no significant additional costs have been incurred due to this testing and so no explicit provision for this is included here.

Secondary Fuel Testing: A provision has been made to constrain on Open Cycle Gas Turbines (OCGTs) during their tests and to constrain on the marginal unit during Combined Cycle Gas Turbine (CCGTs) secondary fuel start up tests for a period of time. A provision has been made for one test for the entire 2021/22 tariff year for all applicable units.

System Operator Interconnector Countertrading: For the 2021/22 forecast, an allowance of €10m for countertrading has been requested. This allowance has been based on the experience of the last 12 months where there has been an increase in the frequency and cost of counter trades. It is anticipated that countertrading will feature more in upcoming 2021/22 year due to tighter capacity margins, high forced outage rates and increasing demand.

2.2.2 Inclusion of supplementary costs for 2021/22

The results of model costs and supplementary costs for 2021/22 are summarised in the table below:

Description	2021/22 Forecast (€m)
PLEXOS Modeled Constraints for 12 Months	291.40
Additional CPREMIUM and CDISCOUNT Impact	23.21
Dispatch of Pump Storage Units	15.58
Block Loading	0.09
Capacity Testing & Performance Monitoring	2.00
Secondary Fuel Testing	0.59
Constrained Wind	5.72
System Operator Interconnector Counter Trades	10.00
Clean Energy Package 2020 and TY 20/21	78.80
Clean Energy Package TY 21/22	45.70
Supplementary Modeling Total	181.69
Total Constraint Costs	473.09

3. Risk Factors

A number of risk factors should be considered when assessing the Imperfections Revenue requirement for 2021/22. The factors are set out below, with brief descriptions of the nature of these risks and potential mitigation measures. These factors could individually or collectively result in a significant deviation between the forecast and actual constraint costs.

3.1 Specific Risks

3.1.1 Reduced Generator Availability and/or Generation Station Closure

A reduction in the overall availability of generation could lead to an increase in DBC as relatively more expensive generation (and/or expensive interconnector countertrades) may be required to provide reserve and/or system support in areas with transmission constraints. Significant deviation from indicative generator scheduled outages and return to service dates could also lead to large variances in DBC.

3.1.2 SEM Design/ Modifications to the SEM Trading and Settlement Code

With the exception of the Clean Energy Package, all assumptions made in this submission were based on the current version of the Market Rules, and the impact of future rule changes has not been considered and must be deemed a potential risk.

3.1.3 Delays and Overruns of Outages

Outages by their nature reduce the flexibility of the system due to unavailability of generation and/or transmission plant. Delays in the scheduled start dates, overrun of any outages and unexpected outages will extend this state of reduced flexibility and may result in an increase in DBC.

3.1.4 Network Reinforcements and Additions

The PLEXOS model was built using the most up to date data available at the time of the data freeze. The commissioning dates of projects in the future may change and any delays or advancements of dates will have an impact on how the system can be operated. Examples of this include delays to network reinforcements, delays to new generator(s) commissioning, unexpected or early generator closures or long-term forced outages. The actual detailed planning of outages is only carried out in the weeks preceding outages as factors such as other transmission outages, generation outages, resourcing, etc. can only be fully realised at this stage.

3.1.5 Interconnector Flows and System Operator Countertrading

Market interconnector flows have been forecasted using historical data from SEM. Participant behaviour could result in interconnector flows that differ greatly from those forecasts. This, in turn, could result in constraint costs changing significantly.

It is possible that the provision we have requested for System Operator Countertrading may be conservative, as a result of reduced generation plant availability and increasing demand, resulting in tighter capacity margins.

3.1.6 Significant Bid Variations

The fuel prices used in the PLEXOS modelling process are based on industry forecasts of long term fuel prices as of May 2021. There is typically considerable volatility in fuel prices in both short and long term timeframes. A general increase in fuel prices would lead to higher generator running costs and hence higher Dispatch Balancing Costs. Other factors such as changes in the cost of carbon, generator Variable Operation and Maintenance (VOM) costs or gas network capacity products could also have a significant impact.

A number of generators include a gas product charge in their offers to the SEM, which has increased DBC. These generators have been taken into account in this forecast. However if any additional gas generators include a gas product charge in their offers this will increase DBC.

3.1.7 High Impact, Low Probability Events (HILPs)

In respect of this forecast, 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 (e.g. due to a fault on an underground cable which could have a long lead times to repair) may result in generation being constrained until the repair can be completed.

PLEXOS does include planned generator outages in the model but these tend to be co-ordinated with transmission outages and they are timed to minimise their impact on constraints. Forced outages for generating units are also modelled to account for some unplanned events. PLEXOS will therefore account for some constraint costs associated with outages but not major HILP events affecting generation and/or transmission plant(s). In such an event involving transmission equipment, the TSOs would obviously seek to implement mitigation measures where possible.

3.1.8 Outturn Availability

A change in practice in relation to the treatment of outturn availability of generators during transmission outages[5] could have an impact on constraint costs.

[5] http://www.eirgridgroup.com/site-files/library/EirGrid/The-EirGrid-and-SONI-Implementation-Approach-to-the-SEM-Committee-Decision-Paper-SEM-15-071-Published-10-February-2016.pdf

3.1.9 Forced Outages of Transmission Plant

The forced outage of 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 potentially increase DBC significantly. For example, if a generator is radially connected to the system and the radial connection is forced out, the impact on DBC can be considerable. In addition, the possibility of equipment failing due to a type fault affecting a particular type or model of equipment installed at numerous points on the transmission system, for example, could have a major impact on constraint costs. Forced transmission outages are not modelled in PLEXOS and no explicit provision has been included due to the unpredictable nature of such outages.

3.1.10 Market Anomalies

Unknown or unintended results from the market scheduling software could lead to unexpected market schedules which form the baseline from which constraints are paid. It is expected that any major anomaly would be quickly identified and corrected to prevent major constraint costs arising.

3.1.11 Participant Behaviour

The PLEXOS modelling process has assumed that participants offer into the market according to their fuel costs and technical availability. There has been no extra provision made for any possible bidding strategy by a market participant as it is assumed the Balancing Market Principles Code of Practice (BMPCOP) is followed for their complex commercial offer data. Therefore the role of the market monitor in monitoring the behaviour of participants and acting in a timely manner is important. Under the revised SEM arrangements, simple bids and offers of generators are not bound by the same guidelines of the BMPCOP. These simple offers and bids set the imbalance price and therefore impact DBC, due to the fact that the TSOs are paying the better of the generator offer and Imbalance price for a non-energy action.

3.1.12 Testing Charges

There is no specific DBC provision for new units that will be under test before they are commissioned, or on return from a significant outage. It is assumed that the testing charges will offset the additional DBC incurred, which will primarily consist of constraints, due to out of merit running (e.g. for the provision of 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).

3.1.13 Contingencies

A list of the principal N-1 contingencies was included in the PLEXOS model. It was assumed that other contingencies had a negligible effect or could be solved post contingency. However, if a significant contingency outside of this list was to occur, and persisted for an extended period, then this could have a significant impact on constraint costs.

3.1.14 Additional Security Constraints

This forecast has been prepared 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, and additional security constraints may be required, resulting in a change in constraint costs.

3.1.15 Long Notice Adjustment Factors

As per SEM-20-075, the Long Notice Adjustment Factor (LNAF) has been set zero until 31/12/2021. A provision of zero was therefore made for the 2021/22 forecast.

3.1.16 Fixed Cost Payments

Fixed Cost Payments (CFC) in the new market comprise of: Make Whole Payment, Recoverable Start Up Costs and Recoverable No Load Costs. A provision for Fixed Cost Payments has not been sought for 2021/22. For 2021/22, from the results of the PLEXOS model, it has been assumed that the majority of these costs have been captured in the PLEXOS model and therefore a separate supplementary component has not been sought. The TSO will consider these costs in future years and a provision may be required in the future, based on future PLEXOS results.

3.1.17 Interconnector Ramp Rate Disparity

Under the revised SEM arrangements an imbalance volume and cost arise as a result of differences in interconnector ramp rates in Euphemia (day ahead pricing algorithm currently in use throughout Europe) and real time operations. In general the higher the ramp rate in Euphemia the higher the imbalance volume and cost. For 2021/22 the TSOs have not sought a provision for this cost, as recent historical data shows the cost to be relatively small. The TSOs will continue to monitor these costs, as a provision may be required in the future, based on further market experience.

4. Imperfections Charge Factor

Under the current SEM arrangements, as per the Trading and Settlement Code Part B, RA approval is required for the Imperfections Charge Factor (**FCIMPy**).

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 of anticipated costs, to seek approval from the RAs to increase the factor, thus increasing 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.

It should be noted that under Section F12.1.4 it is only possible for the Imperfections Charge Factor to be adjusted to effectively increase the rate at which monies are being recovered within a year; there is no clause that provides for the Factor to be set to reduce the rate of recovery.

As such, and in accordance with Section F.12.1.1 (b), EirGrid and SONI are now seeking the approval for the Imperfections Charge Factor to be set to 1 for the period of 1 October 2021 to 30 September 2022.

5. Total Revenue & Regulatory Cost Recovery

Given the extent of total DBC, and in the context of increased unpredictability and volatility seen under the revised market arrangements, the principle of costs being 100% pass-through through, the k factor as per the current arrangements is of paramount importance. 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.

Under Section F.22 of Part B of the Trading and Settlement Code, which addresses actions to be taken in the event of working capital shortfalls, the business will cease making payments out in the event that the standby debt facilities' limits are hit. In this context it is of absolute importance that the Imperfections Charge is set against the full forecast provided in this paper, along with the full k factor which is being submitted separately.

Appendix 1: Overview of Imperfections and Modelling Constraint Costs

1. Overview of Imperfections

The purpose of the Imperfections Charge under the revised SEM arrangements remains similar to that in the old market i.e. to recover the anticipated Dispatch Balancing Costs (less Other System Charges), Fixed Cost Payments, over the Year, with adjustments for previous years as appropriate. As noted in Section 1, adjustments for previous years are not included in this submission, but are considered in setting the Imperfections Charge.

2. Constraint Costs

2.1 Overview of Constraint Costs

Constraint costs are the largest portion of the DBC. The TSOs, in ensuring continuity of supply and the security of the system in real time, have to dispatch some generators differently from the output levels indicated by the ex-post 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') and the actual instructions issued to generators (the 'actual 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 of these changes in generator dispatch quantities.

The actual dispatch of generation is based on the same commercial data as used in the production of the market schedule. However, the TSOs must take into account the technical realities of operating the power system. As such, dispatch will deviate from the market schedule to ensure security of supply. Constraint costs arise whenever dispatch and market schedule diverge.

Section 2 below describes the main categories of issues that can lead to a difference between the market schedule and actual dispatch and hence constraint costs.

2.2 Why do Constraint Costs Arise?

2.2.1 Transmission

In order to ensure the safe and secure operation of the transmission network, 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.

2.2.2 Reserve

In order 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. To maintain the demand-supply balance, some generators will be constrained 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.

2.2.3 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 that generators can synchronise and reach their minimum load level in 15 minutes, whereas in reality this may take much longer; 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.

2.3 Managing Constraint Costs

Constraint costs will inevitably arise due to the factors described above and they are also dependent on a number of underlying conditions. Some of these conditions, such as fuel costs, generator forced outages, trips, start times, overruns of transmission outages, 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. The TSOs undertake a number of measures to control and mitigate the costs of re-dispatching the system.

These measures include, but are not limited to:

- Performance Monitoring, which identifies levels of reserve provision and Grid Code compliance. The TSOs also analyse the performance of each unit following a system event and follow up with those units that do not meet requirements or do not respond according to contracted parameters.
- Applying Other System Charges (OSC) on generators whose failure to provide necessary services to the system lead to higher DBC. OSC include charges for generator units that trip, for those which make downward declarations of availability at short notice and Generator Performance Incentives (GPIs). GPIs monitor the performance of generator units against the Grid Code and help quantify and track generator performance, identity non-compliance with standards and assist in evaluating any performance gaps.
- Wind, Solar and Load forecasting, which involves continually working with vendors to improve forecast accuracy.
- Development of system services will provide a system benefit.

2.4 Modelling Constraint Costs

2.4.1 Approach to Constraints Forecasting

Detailed market, transmission system and generation models were developed and analysed utilising the simulation package PLEXOS, which captures the key transmission and reserve constraints. Supplementary modelling was then used to examine factors affecting constraints that could not be accurately modelled in PLEXOS.

As this is an estimate of constraints approximately a year ahead, the assumptions that are made are critical to the forecast. Where possible, data from the market, such as Commercial and Technical Offer data, historical dispatch quantities, market schedule quantities and constraint payments, has been used to review key assumptions.

In the following sections, details of the key assumptions, the PLEXOS model and the analysis of specific effects on DBC are presented.

2.4.2 Key Modelling Assumptions

The TSOs have made a number of assumptions in preparing this submission. The principal ones are:

- Where reference is made to the Trading and Settlement Code (T&SC), the version referred to is Part B dated 19 April 2019.
- For the purpose of this submission all expenditure and tariffs are presented in euro. The euro foreign exchange rates from the European Central Bank are used for any money originally in pounds sterling and US dollars.

Appendix 2 lists the key assumptions used in the production of the constraints in PLEXOS for the TSOs' Imperfections revenue requirements forecast.

2.4.3 PLEXOS Modelling

PLEXOS for Power Systems is a modelling tool which can be used to simulate the SEM. It can be used to forecast constraints over an annual time horizon using the best available data and assumptions. However, like all models, it will never fully reflect operational reality and cannot be used to derive an estimate for any one specific day. As the model was set up for a 12 month study horizon it is important that all results are considered according to this timeframe, rather than being considered for specific months and/or periods of the tariff year in isolation.

This analysis used a model of the transmission and generation systems across the whole island, with assumptions around factors such as outage schedules, demand levels, plant availability, fuel prices and wind output. The model also took account of reserve requirements and specific transmission constraints, so that the effect in terms of total production costs could be analysed.

It assumed that, in line with the Bidding Code of Practice, the generators bid their short run marginal cost into the market and this was the basis for setting the system marginal price and determining constraint costs. The difference in production costs between the unconstrained (market) simulation and the constrained (dispatch) simulation represents the constraint costs associated with the modelled transmission and reserve constraints.

Appendix 2: PLEXOS Modelling Assumptions

PLEXOS is used by the TSOs 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:

The Transmission Network

These are the lines, cables and transformers operated by SONI and EirGrid. PLEXOS allows for the addition of new equipment, decommissioning of old equipment, up-ratings and periods when items are taken out of service.

Generation/Interconnection

There is a detailed representation of all generators in the PLEXOS model. This includes ramp rates, minimum and maximum generation levels, start-up times, reserve capabilities, fuel types and heat rates which are all modelled. Outages of generators, commissioning of new plant and decommissioning of old plant can all be represented.

Demand

Hourly variations in system demand are modelled down to the appropriate supply point.

Fuel Prices

Fuel prices for 2021/22 are defined in €/GJ based on the long term fuel forecasts from Thomson-Reuters Eikon[6] and data gathered by the TSOs. Carbon costs are also forecast and used, along with fuel costs, to simulate bids.

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

General

Feature	Assumptions
Study Period	The study period is 01/10/2021 to 30/09/2022
Data Freeze	Majority of input data for the PLEXOS model was frozen at the end of March 2021
Generation Dispatch	Two hourly generation schedules are examined: one schedule to represent the dispatch quantities (constrained) and 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.

[6] https://thomsonreuterseikon.com/

Demand

Feature	Assumptions
Load	The demand is based on the median forecast for both Northern Ireland and Ireland from the All-island Generation Capacity Statement 2021. 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

Feature	Assumptions
Generation Resources	Conventional generation resources are based on the All-island Generation Capacity Statement 2021-2030.
Fuel and Carbon Prices	Fuel prices for 2021/22 are based on the long term fuel forecasts from Thomson-Reuters Eikon[7], the US Energy Information Administration[8] and data gathered by the TSOs. The cost of European Union Allowances (EUAs) for carbon under the EU Emissions Trading Scheme (EU-ETS) are taken from ICE EUA Carbon Futures index.
Production Costs	Calculated through PLEXOS. The inputs to PLEXOS were based on analysis of actual bids. 1. Fuel cost (€/GJ) – forecasted for 2021/22 from Thomson Reuters and the US Energy Information Administration 2. Piecewise linear heat rates (GJ/MWh) 3. No Load rate (GJ/h) 4. Start energies (GJ) 5. Variable Operation & Maintenance Costs (€/MWh) A fixed element of start-up costs is calculated based on historical analysis of commercial offer data.
Generation Constraints (TOD)	Based on the data in the PLEXOS Public Model for 2018-23[19] and Technical Offer Data in the SEM, the following technical characteristics are implemented: 1. Maximum Capacity 2. Minimum Stable Generation 3. Minimum up/down times 4. Ramp up/down limits 5. Cooling Boundary Times
Generator Scheduled Outages	2021 and 2022 maintenance outages are based on provisional outage schedules. Return Dates for the units are based on the

[7] https://thomsonreuterseikon.com/
[8] https://www.eia.gov/

Feature	Assumptions
	latest available information from the Generator units as of the data freeze.
Forced Outages	Forced outages of generators are determined using a method known as Convergent Monte Carlo. Forced Outage Rates are based on EirGrid/SONI forecasts and Mean Times to Repair information is based on the 2021/22 Validated SEM Generator Data Parameters.
Hydro Generation	Hydro units are modelled using daily energy limits. Other hydro constraints (such as drawdown restrictions and reservoir coupling) are not modelled.
Priority Dispatch Generation	Wind and solar generation resources are based on MW currently installed plus an anticipated rate of connection as per the All-Island Generation Capacity Statement 2021-2030.
Turlough Hill	Modelled as 4 units of 73 MW. The usable reservoir volume is 1,540MWh. The efficiency of the unit is modelled as 70% in the unconstrained and 54% in the constrained model.
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.
Multi-Fuel Modelling	Only one fuel is modelled for each generating unit. The coal units at Kilroot, while able to run on oil, almost never do so, and will be modelled as coal only. Note that where units are multi fuel start this is modelled explicitly using one fuel offtake for each fuel. Multi fuel start units are Kilroot units one and two, Moneypoint units one, two and three and Tarbert units one, two, three and four.
Interconnector Flows	Interconnector flows with BETTA are forecast based on actual flows derived from the new market.
DS3/Operational Pathways to 2030 milestones	System Non-Synchronous Penetration (SNSP) is set at 75% in the constrained PLEXOS model from Oct 2021. During the year, it is assumed that the minimum number of sets is reduced from 8 to 7 and subsequently that the minimum level of inertia is reduced from 23GWs to 20GWs.

Transmission

Feature	Assumptions
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 TSO operational experience, are modelled.
Transmission	Transmission constraints are only represented in the

Feature	Assumptions
Constraints	constrained model. The market schedule run is free of transmission constraints.
Network Load Flow	A DC linear network model is implemented.
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-BETTA model. The Net Transfer Capacity (NTC) is modelled for the constrained schedule, which is assumed to be 325 MW N-S and 200 MW S-N.
Interconnection	The Moyle Interconnector and EWIC are modelled.
Forced Outages	No forced outages are modelled on the transmission network.
Transmission Scheduled and Forced Outages	The outage requirements for the 2021/22 are based on the best available information, as of April 2021. The outages assumed in the forecast are indicative only and subject to change. Forced transmission outages are not modelled.

Ancillary Services

Feature	Assumptions
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[9]
Other Reserve Sources	For this forecast that DSUs, interconnectors and batteries will also provide reserve in the model.

[9] https://www.eirgridgroup.com/site-files/library/EirGrid/OperationalConstraintsUpdateVersion1_105_April_2021.pdf

Appendix 3: Transmission Outages

A list of the major outages, based on provisional outage schedules, which were used in the constrained model, is shown below. The outage requirements for the 2021/22 are based on the best available information, as of April 2021. The outages assumed in the forecast are indicative only and subject to change.

Circuit/Plant	Date From	Date To
Athy - Portlaoise_110_1	28/02/2022	15/04/2022
Ballynahulla - Knockanure_220_1	04/08/2021	06/10/2021
Ballynahulla - Knockanure_220_1	09/11/2021	26/11/2021
Ballyvouskil - Ballynahulla_220_1	01/05/2022	30/10/2022
Ballyvouskil - Clashavoon - 220_1	07/10/2021	27/10/2021
Bellacorick - Castlebar_110_1	21/04/2022	10/05/2022
Bellacorick - Moy_110_1	01/04/2022	20/04/2022
Cahir - Tipperary_110_1	07/03/2022	07/06/2022
Cahir Barrymore-T_110_1	08/08/2022	30/10/2022
Carlow - Kellis_110_2	05/11/2021	18/11/2021
Carrigadrohid - Macroom_110_1	20/09/2021	20/10/2021
Cashla - Cloon_110_1	04/10/2021	01/11/2021
Cashla - Galway_110_1	12/08/2021	29/10/2021
Cashla - Prospect_220_1	01/05/2022	31/05/2022
Castlebar - Cloon_110_1	01/08/2022	30/10/2022
Clashavoon - Macroom_110_2	20/09/2021	20/10/2021
Clonee - Woodland_220_1	03/09/2021	28/10/2021
Cloon - Lanesboro110_1	28/02/2022	28/04/2022
Corduff - Platin_110_1	10/06/2021	26/11/2021
Corduff - Platin_110_1	03/03/2022	30/06/2022
Corduff - Mullingar_110_1	11/10/2021	22/10/2021
Corduff - Mullingar_110_1	28/02/2022	31/08/2022
Corduff - Ryebrook_110_1	28/02/2022	12/05/2022
Dungarvan - Woodhouse_110_1	27/09/2021	08/10/2021
Finglas - North Wall_220_1	28/02/2022	21/03/2022
Finglas - North Wall_220_1	15/08/2022	30/10/2022
Flagford - Louth_220_1	01/09/2022	30/09/2022
Glenree Moy_110_1	02/11/2021	15/11/2021
Glenree Moy_110_1	11/05/2022	31/05/2022

Circuit/Plant	Date From	Date To
Great Island - Kellis_220_1	16/04/2022	04/05/2022
Great Island - Kilkenny_110_1	18/05/2021	06/10/2021
Inchicore - Irishtown_220_1	30/04/2022	20/06/2022
Irishtown - Shellybanks_220_1	30/04/2022	20/06/2022
Kellis - Kilkenny_110_1	01/06/2022	30/10/2022
Kilbarry - Knockraha_110_2	28/02/2022	28/07/2022
Killonan - Shannonbridge_220_1	01/06/2022	30/06/2022
Kilpaddoge - Tarbert_220_1	06/08/2021	19/11/2021
Kinnegad - Dunfirth-T_110_1	26/10/2021	08/11/2021
Knockanure - Trien_110_2	06/09/2021	08/11/2021
Lisdrum - Louth_110_1	11/10/2021	22/10/2021
Louth - Woodland_220_1	01/08/2022	31/08/2022
Louth coupler - a_220_1	28/02/2022	10/11/2022
Maynooth - Woodland_220_1	22/07/2021	26/11/2021
Maynooth - Woodland_220_1	28/02/2022	28/04/2022
Oldstreet - Woodland_380_1	01/07/2022	31/07/2022
Clashavoon T2101	01/03/2021	08/11/2021
Dunstown T4201	06/09/2021	01/11/2021
Gorman T2102	04/07/2022	04/09/2022
Kellis T2101	21/10/2021	04/11/2021
Moneypoint T4202	28/02/2022	22/06/2022
Srananagh T2102	01/06/2022	20/06/2022
Woodland T4201	30/05/2022	04/07/2022
Woodland T4202	20/09/2021	15/10/2021
Ballylumford Eden ckt 1	01/04/2022	30/09/2022
Ballylumford Eden ckt 2	01/04/2022	30/09/2022
Coolkeeragh (COOL2A) - Magherafelt 275 ckt 1	01/04/2022	30/09/2022
Omagh to Dromore 110 ckt 1	01/05/2022	30/06/2022

Appendix 4: N-1s

A list of the N-1 contingencies which are utilised in the model is displayed below.

Loss of Aghada Glanagow 220	Loss of Derryiron Kinnegad
Loss of Aghada-Knockraha 1	Loss of Derryiron Thornsberry
Loss of Aghada-Knockraha 2	Loss of Derryiron to Maynooth
Loss of Aghada-Raffeen 1	Loss of Drumkeen Letterkenny
Loss of Arklow Carrickmines 220	Loss of Drumline Ennis
Loss of Arklow Lodgewood	Loss of Drybridge Gorman
Loss of Ballynahulla Knockanure	Loss of Drybridge Louth
Loss of Ballyvouskil Ballynahulla	Loss of Drybridge Platin
Loss of Ballyvouskil Clashavoon	Loss of Dungarvan-Woodhouse
Loss of Cashla Flagford	Loss of Dunmanway Macroom
Loss of Cashla Prospect	Loss of Flagford-Sliabh Bawn
Loss of Cashla Tynagh 220kV	Loss of Flagford-Sligo
Loss of CKM-Dunstown 220kV	Loss of Galway Salthill
Loss of CKM-Irishtown 220kV	Loss of Gorman - Meath Hill
Loss of CKM-Poolbeg 220 and PST	Loss of Gorman-Platin
Loss of Carrickmines - Poolbeg_220_1	Loss of Gorman-Navan 3
Loss of Clashavoon Knockraha 220	loss of Great Island - Kilkenny
Loss of Clonee Corduff 220	loss of Great Island - Wexford
Loss of Clonee Woodland 220	loss of Great Island - Waterford 1
Loss of Corduff - Finglas 220 2	Loss of Iniscara Macroom
Loss of Corduff Finglas 220 1	Loss of Kellis Kilkenny
Loss of Corduff Woodland 220 1	Loss of Kilbarry Knockraha 1
Loss of Cullenagh-Great Island 220	Loss of Kilbarry Mallow
Loss of Cullenagh-Knockraha 220	Loss of kilbarry marina 2
Loss of Dunstown - Maynooth_220_2	Loss of Kill Hill – Thurles
Loss of Dunstown-Kellis 220	Loss of Killonan-Limerick 1
Loss of Dunstown-Maynooth 220 1	Loss of Killonan-Limerick 2
Loss of Dunstown-Turlough Hill 220	Loss of Killonan-Singland
Loss of Finglas to Shellybanks 220	Loss of Kilpaddoge - Tralee ckt 2
Loss of Finglas - Belcamp_220_1	Loss of Kilpaddoge Knockanure 1
Loss of Finglas North Wall 220	Loss of Kilpaddoge Rathkeale
Loss of Flagford-Louth 220	Loss of Kilteel Maynooth
Loss of Flagford-Srananagh 220	Loss of Kilteel Monread
Loss of Glanagow Raffeen 220	Loss of Kinnegad to Mullingar
Loss of Gorman-Louth 220	Loss of Kinnegad Dunfirth T
Loss of Gorman-Maynooth 220	Loss of Knockraha - Barrymore T
Loss of Great Island - Kellis 220	Loss of Knockraha Woodhouse
Loss of Great Island - Lodgewood 220	Loss of Lanesboro Mullingar
Loss of Inchicore - Maynooth_220_1	Loss of Lanesboro-Sliabh Bawn
Loss of Inchicore - Poolbeg_220_1	Loss of Letterkenny Golagh T
Loss of Inchicore - WestDublin_220_1	Loss of Letterkenny Tievebrack
Loss of Inchicore Poolbeg 220 2	Loss of Limerick Moneteen
Loss of Inchicore-WestDublin 220 2	Loss of Limerick Rathkeale

Loss of Inch-Irishtown 220	Loss of Lisdrum Louth
Loss of Irishtown Shellybanks 220	Loss of Lisdrum Shankill
Loss of Killonan Knockraha 220	Loss of Louth - Meath Hill
Loss of Killonan Shannonbridge 220	Loss of Louth – Ratrussan
Loss of Killonan Tarbert 220	Loss of Marina Trabeg 1
Loss of Kilpaddoge Knockanure 220 1	Loss of Marina Trabeg 2
Loss of Kilpaddoge Moneypoint 220 1	Loss of Maynooth Blake T
Loss of Kilpaddoge Moneypoint 220 2	Loss of Maynooth Rinawade
Loss of Kilpaddoge Tarbert 220 1	Loss of Maynooth Ryebrook
Loss of Knockraha-Raffeen 220	Loss of Mount Lucas - Thornsberry
Loss of Louth Tandragee ckt 1 275	Loss of Newbridge Blake T
Loss of Louth-Oriel (Woodland) 220	Loss of Portlaoise Dallow T
Loss of Maynooth - WestDublin_220_1	Loss of Portlaoise to Newbridge
Loss of Maynooth Shannonbridge 220	Loss of Raffeen-Trabeg 1
Loss of Maynooth to Woodland 220	Loss of Raffeen-Trabeg 2
Loss of Maynooth Turlough Hill 220	Loss of Ratrussan Shankill
Loss of Maynooth-WestDublin 220 2	Loss of Rinawade Dunfirth T
Loss of Moneypoint-Prospect	Loss of Shannonbridge - Dalton T
Loss of North Wall - Poolbeg	Loss of Shannonbridge - Somerset T
Loss of Oldstreet Tynagh	Loss of Shannonbridge - Ikerrin T
Loss of Poolbeg - Shellybanks_220_1	Loss of Sligo Srananagh 1
Loss of Prospect-Tarbert	Loss of Tralee - Oughtragh T
Loss of Agannygal Ennis	Loss of AD 220-110 1
Loss of Agannygal Shannonbridge	Loss of ARK 220-110 1
Loss of Aghada Whitegate	Loss of ARK 220-110 2
Loss of Ardnacrusha Drumline	Loss of CLA 220-110 1
Loss of Ardnacrusha Ennis	Loss of CLA 220-110 2
Loss of Ardnacrusha Limerick	Loss of CSH 220-110 1
Loss of Ardnacrusha-Singland	Loss of CSH 220-110 2
Loss of Arklow Ballybeg	Loss of CUL 220-110 1
Loss of Arklow Banoge	Loss of dn 380-220 1
Loss of Arva Carrick on Shannon	Loss of dn 380-220 2
Loss of Arva Gortawee	Loss of fla 220-110 1
Loss of Arva Navan	Loss of fla 220-110 2
Loss of Arva Shankill 2	Loss of GI 220-110 1
Loss of Athlone Lanesboro	Loss of GI 220-110 2
Loss of Athlone Shannonbridge	Loss of KLN 220-110 3
Loss of Athy to Portlaoise	Loss of KLN 220-110 4
Loss of Aughinish Kilpaddoge	Loss of KPD 220-110 1
Loss of Ballybeg Carrickmines	Loss of KPD 220-110 2
Loss of Baltrasna Corduff	Loss of kra 220-110 1
Loss of Baltrasna Drybridge	Loss of kra 220-110 2
Loss of Bandon Dunmanway	Loss of kra 220-110 3
Loss of Bandon Raffeen	Loss of Laois 400-110 1
Loss of Banoge to Crane	Loss of LDG 220-110 1
Loss of Baroda Newbridge	Loss of LOU 220-110 1
Loss of Bellacorick-Castlebar	Loss of LOU 220-110 2
Loss of Bellacorick-Moy	Loss of MAY 220-110 1
Loss of Binbane Tievebrack	Loss of MAY 220-110 3

Loss of Binbane-CF	Loss of Cushaling Portlaoise
Loss of Booltiagh Ennis	Loss of MP 220-110 1
Loss of Butlerstown Cullenagh	Loss of MP 380-220 1
Loss of Cahir - Barrymore T	Loss of MP 380-220 2
Loss of Cahir - Kill Hill	Loss of raf 220-110 1
Loss of Cahir Tipperary	Loss of raf 220-110 2
Loss of Cahir-Doon	Loss of SH 220-110 1
Loss of Carlow Kellis 1	Loss of wo 380-220 1
Loss of Carrick on Shannon - Arigna T	Loss of wo 380-220 2
Loss of Carrick on Shannon - Flagford	Loss of dunstown laois 400
Loss of Carrigadrohid Kilbarry	Loss of dunstown moneypoint 400
Loss of Carrigadrohid Macroom	Loss of Moneypoint Oldstreet 400
Loss of Cashla Cloon	Loss of Oldstreet Woodland 400
Loss of Cashla Dalton	Loss of Inchicore-Maynooth 220 2
Loss of Cashla Ennis	Loss of Kilpaddoge Tarbert 220 2
Loss of cashla galway 2	Loss of BAFD BCRM 275kV SC
Loss of cashla salthill	Loss of BAFD HANA 275kV SC
Loss of Cashla to Somerset T	Loss of BAFD KELL 275kV SC
Loss of Castlebar Cloon	Loss of BCRM HANA 275kV SC
Loss of Castlebar Dalton	Loss of CAST HANA 275kV SC
Loss of Cauteen Killonan	Loss of CAST TAND 275kV SC
Loss of CF clogher 110kV	Loss of CAST to KILR 275kV SC
Loss of CF-Corraclassy	Loss of Cool-magh 275 SC
Loss of CF-Srananagh 2	Loss of KELL KILR 275kV SC
Loss of Charleville Killonan	Loss of KELL MAGF 275kV SC
Loss of Clahane Tralee	Loss of KILR to TAND 275kV SC
Loss of Clahane Trien	Loss of MAGF TAMN 275 SC
Loss of Clashavoon Clonkeen	Loss of TAND TAMN 275 SC
Loss of Clashavoon Macroom 1	Loss of COLE1- COOL1-
Loss of Clashavoon Macroom 2	Loss of COLE1- LIMA1-
Loss of Clogher-Drumkeen	Loss of COLE1- Rasharkin
Loss of Clogher-Golagh T	Loss of COOL1- KILL1-CL
Loss of Clonkeen Clashavoon	Loss of COOL1- Limavady
Loss of Clonkeen Knockearagh	Loss of COOL1- stra
Loss of Cloon Lanesboro	Loss of DUNG to OMAH1-
Loss of Coolroe Kilbarry	Loss of Dungannon-Tamnamore
Loss of Corderry Arigna T	Loss of Gort Omagh
Loss of Corderry Srananagh	Loss of KELS1- RASH1-
Loss of Corduff to Mullingar	Loss of Killmallaght Strabane
Loss of Corduff to Platin	Loss of Omagh OmaS
Loss of Corduff-Ryebrook	Loss of Omagh Tremoge
Loss of Corraclassy Gortawee	Loss of OMAH1- STRA1-
Loss of Crane Wexford	Loss of Tamnamore Tremoge
Loss of Cullenagh to Dungarvan	Loss of BAFD 275 110 ckt 1
Loss of Cullenagh to Ballydine	Loss of CAST 275 110 ckt 1
Loss of Cullenagh-Waterford	Loss of cool 275 110 ckt 1
Loss of Cunghill Sligo	Loss of kell 275 110 ckt 1
Loss of Cushaling - Mount Lucas	Loss of TAMN 275 110 ckt 1
Loss of Cushaling Newbridge	Loss of TAND 275 110 ckt 1

Appendix 5: Glossary

AGU	Aggregated Generator Unit
ATR	Associated Transmission Reinforcements
BETTA	British Electricity Trading and Transmission Arrangements
CCGT	Combined Cycle Gas Turbine
CRU	Commission for Regulation of Utilities
DBC	Dispatch Balancing Costs
DSU	Demand Side Unit
EWIC	East West Interconnector
GPI	Generator Performance Incentive
HILP	High Impact Low Probability
LPF	Load Participation Factor
MIUN	Modified Interconnector Unit Nomination
MSQ	Market Schedule Quantities
MW	Megawatt
MWh	Megawatt hour
NTC	Net Transfer Capacity
OCGT	Open Cycle Gas Turbine
OSC	Other System Charges
RA	Regulatory Authority
RoCoF	Rate of Change of Frequency
SEM	Single Electricity Market
SEMO	Single Electricity Market Operator
SMP	System Marginal Price
SO	System Operator
SSS	System Support Services
STAR	Short Term Active Response
T&SC	Trading and Settlement Code
TCG	Transmission Constraint Group
TSO	Transmission System Operator
TUoS	Transmission Use of System
UUC	Unconstrained Unit Commitment
UR	Utility Regulator for Northern Ireland
VOM	Variable Operation and Maintenance

Appendix 6: SEM Settlement Cost Components

Dispatch Balancing Costs are made up of the following components:

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, 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.

CFC: 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.

CTEST: Charges applied to units under test.

CUNIMB: 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.