Forecast Imperfections Revenue Requirement

For Tariff Year 2017/18

EIRGRID SONI

Executive Summary

This submission represents the Transmission System Operators (TSOs) forecast of the revenue requirement to be recovered through Imperfections Charge/Tariff during the 2017/18 tariff year.

The purpose of the Imperfections Charge/Tariff is to recover the total expected costs associated with Dispatch Balancing Costs (less Other System Charges), Make Whole Payments, imbalances between Energy Payments and Energy Charges and Capacity Payments and Capacity Charges. Adjustments for previous years are also considered by the Regulatory Authorities in their final decision on the Imperfections Charge/Tariff however this is due to be provided later to capture the most up-to date information.

The forecast revenue requirement based on a large number of assumptions and expected conditions for the 2017/18 tariff year period (01/10/2017 to 30/09/2018) is €213.57 million in nominal terms. This is an increase of €66.77m over the equivalent 2016/17 requirement of €146.8 million, which itself was reduced by a significant €78 million k-factor when the final decision on Imperfection Charges was made. It is not expected that there will be an equivalent k-factor submitted this year.

Constraint costs represent the largest proportion of the forecast revenue requirement and this paper describes in detail the methodology employed in the forecasting process.

One of the important differences between the 2017/18 forecasting process and that of previous years is that it spans both SEM and I-SEM operation periods. The approach taken in the underlying forecast has been to use one PLEXOS model for the entire tariff year for both markets which assumes that the Dispatch Balancing Costs in I-SEM will remain based on the production cost difference between the unconstrained and constrained models. There are also a number of additional assumptions and considerations included specific to the I-SEM portion of the year (23/05/2018 to 30/09/2018). It is important to note that due to the high number of unknowns associated with I-SEM at this stage, in many cases the TSOs had to make high level assumptions (where possible) to estimate these new cost drivers.

The key factors which have influenced the total constraint cost forecast for 2017/18 of €196.37 million are:

- Over 20% increase in available priority dispatch generation in the unconstrained PLEXOS model contributes to an additional €14.23 million compared to the 2016/17 forecast.
- Approximately €30 million forecast costs associated with I-SEM related uncertainties are also included. This includes a €16.3m provision for the uncertainty which pertains through the change in rules for the greater of imbalance prices and bid prices in I-SEM and €10.77m to account for new interconnector ramping rates.

In addition, in compensation for the absence, of access to SONI debt facilities, due to the current SONI Price Control arrangements, a €14.5m (£12m) provision has been added to the total revenue requirement. This is effectively to act as a tariff cash replacement for the debt facilities which to date have been in place to provide funding in the event of inadequate revenues, higher costs or timing mismatches.

The TSOs have outlined a number of risk factors, which could have a significant impact on constraint costs and the total imperfections revenue requirement, were they to occur.

The main components of the 2017/18 forecast revenue requirement submission are set out in the following table:

Component	Forecast (€ million)
PLEXOS Modelling	**140.04**
Supplementary Modelling	**56.33**
Make Whole Payments	**2.7**
SONI Debt Replacement	**14.5**
Total 2017/18 Forecast Imperfections Revenue Requirement	**213.57**

1. Introduction

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

The submission reflects the TSOs' forecast of the revenue required from the Imperfections Charge/Tariff for the 12 month period from 01/10/2017 to 30/09/2018 inclusive, referred to as the tariff year 2017/18.

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. In addition to DBC, the forecast also makes provision for Energy Imbalances, Make Whole Payments and Other System Charges for the tariff year 2017/18. Other elements also contribute in setting the regulated Imperfections Charge/Tariff including the Imperfections K factor, which adjusts for previous years as appropriate, and the forecast system demand.

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

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 and SSS tariff in Ireland and Northern Ireland under the respective regulatory arrangements pertaining. This year the submission does include a tariff provision for the SONI TSO element of the standby facilities. This is included in order to ensure the TSOs have similar funding arrangements in place as is extant.

The TSOs' forecast for the Imperfections revenue requirement is €213.57 million in nominal terms for the tariff year 2017/18. A detailed breakdown of the forecast individual components is contained in Section 2.

1.1 Context for Tariff Year 2017/2018

There are a number of factors which may influence the forecast Constraint costs, and hence the Imperfections revenue requirement, for the tariff year 2017/18. The most significant influencing factors are described in the following sections.

As previously referred the 2017/18 tariff year is composed of two operation modes – the first under the SEM (01/10/2017 to 22/05/2018) and the second under I-SEM (23/05/2018 to 30/09/2018). The uncertainties with regard to the latter makes the 2017/18 forecast particularly difficult to ascertain and increases the potential for Imperfections revenues not being sufficient enough to pay for actual costs when they arise. In turn this places greater financial pressure on the TSOs to ensure they are in a position to finance any underfunding should this be the case. If the TSOs are not in a position to do so, the Regulatory Authorities should ensure that there are appropriate arrangements in place to implement a revised Imperfections Charge/Tariff mid-year and/or that all parties, including participants, are aware of and accept the consequences of potential payment delays.

1.1.1 Background of I-SEM

The Integrated Single Electricity Market (I-SEM) is a new wholesale electricity market arrangement for Ireland and Northern Ireland. 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.

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. The long-term model for a single European trading platform is based on continuous cross border trading. However, at go-live, intraday trading is only continuous within the SEM (within-zone), where bids and offers are continuously matched on a first-come-first-served basis. Three cross-border intraday auctions are also run using a version of the DAM algorithm.

The Balancing Market (BM) determines the imbalance price for settlement of the TSO's 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 spot price in each 5 minute imbalance pricing period. The highest priced unflagged offer that is dispatched sets the imbalance price in each period. The flag-and-tag process excludes bids and offers that are scheduled due to system constraints. 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. Energy actions in the BM are settled at the imbalance price. Additional payments or charges are incurred for uninstructed deviations from the schedule at the imbalance settlement price. Non-energy actions (e.g. reserves, voltage, congestion on lines, etc.) are settled at either the bid or offer price or the imbalance price, depending on whether the generating unit is constrained up or down.

1.1.2 Modelling approach for Tariff Year 2017/18

I-SEM arrangements are due to go live on 23/05/2018. This has the potential to be the most influential factor in the 2017/18 imperfections outturn. The reason being that there are a large number of unknowns associated with the introduction of I-SEM. Unknown factors associated with I-SEM include the imbalance price, the incremental and decremental prices of generators, the Physical Notifications (PNs) of generators and the interconnector ramp rates used in the I-SEM reference program. It is assumed for the purposes of this forecast that generator offers in I-SEM will continue to be based on their short run marginal costs. The reason for this is that without actual data to go on an assumption needs to be made on what generator PNs will be. Using the current SRMC of generators in SEM to approximate their PNs in I-SEM is the most reasonable approach at the time of data freeze of this submission. As such the TSOs have used one PLEXOS model for the 2017/18 tariff year. This means that a production cost based model has been used for both the SEM and I-SEM portions of the tariff year. However, in addition to PLEXOS modelling the TSOs have estimated the potential impact to imperfections of specific I-SEM related factors for tariff year 2017/18 within supplementary modelling.

1.1.2 Generation Merit Order

Compared to the tariff year 2016/17 forecast, there has been a change in the generation mix available in the market. In particular there is a large increase in priority dispatch generation from Wind, Solar and waste to energy. Compared to 2016/17 there is over 20% more priority dispatch generation available to the unconstrained model in the 2017/18 forecast. This coupled with cheaper forecast gas prices in 2017/18 leads to a lower unconstrained production cost in PLEXOS. Figure 1 outlines the differences in the forecast fuel prices from the 2016/17 forecast to the 2017/18 forecast.

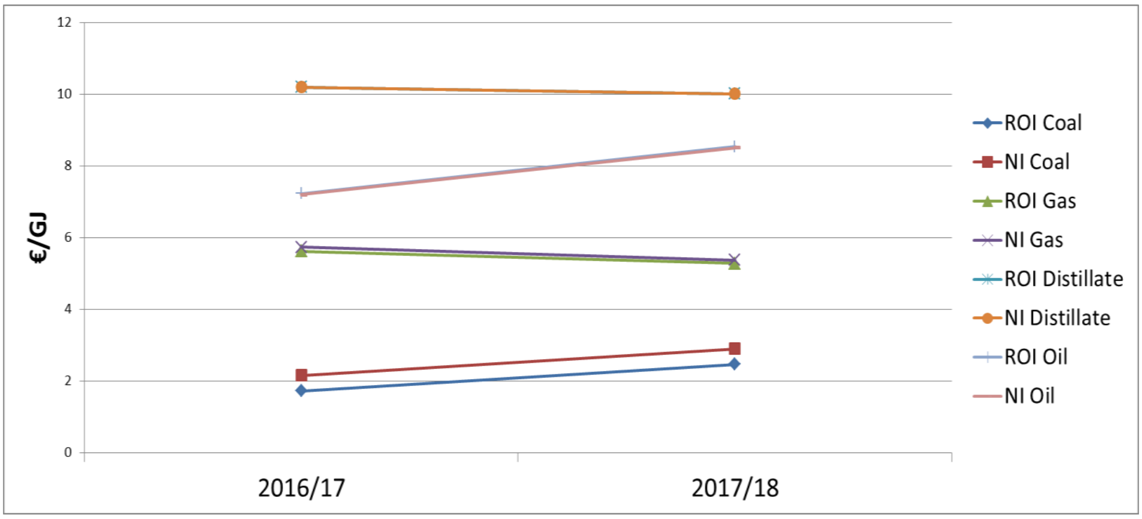

Figure 1: Forecast Model Fuel Cost Changes from 2016/17 to 2017/18

It has been assumed, based on the recent participant bidding behaviour that eleven gas-fired generation units in Ireland and 5 gas fired generators in Northern Ireland will continue to include the cost of particular gas network capacity products into 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 where they are constrained on in dispatch to meet reserve, transmission or security constraints on the power system.

1.1.3 Interconnection

Since the increase in the Carbon Price Floor in Great Britain (GB) in April 2015 market interconnector flows on both Moyle and the East West Interconnector (EWIC) have resulted in the price spread between SEM and GB narrowing significantly as seen in Figure 2. This increase in Carbon Price Floor resulted in significant exports from SEM during the night and then imports, albeit at a reduced level, to SEM during the day. There has also been an increase in the number of market participants registered to trade on both interconnectors. The result of this is that there is greater trading on both interconnectors based on price spreads and this can be clearly seen during periods of high wind in SEM.

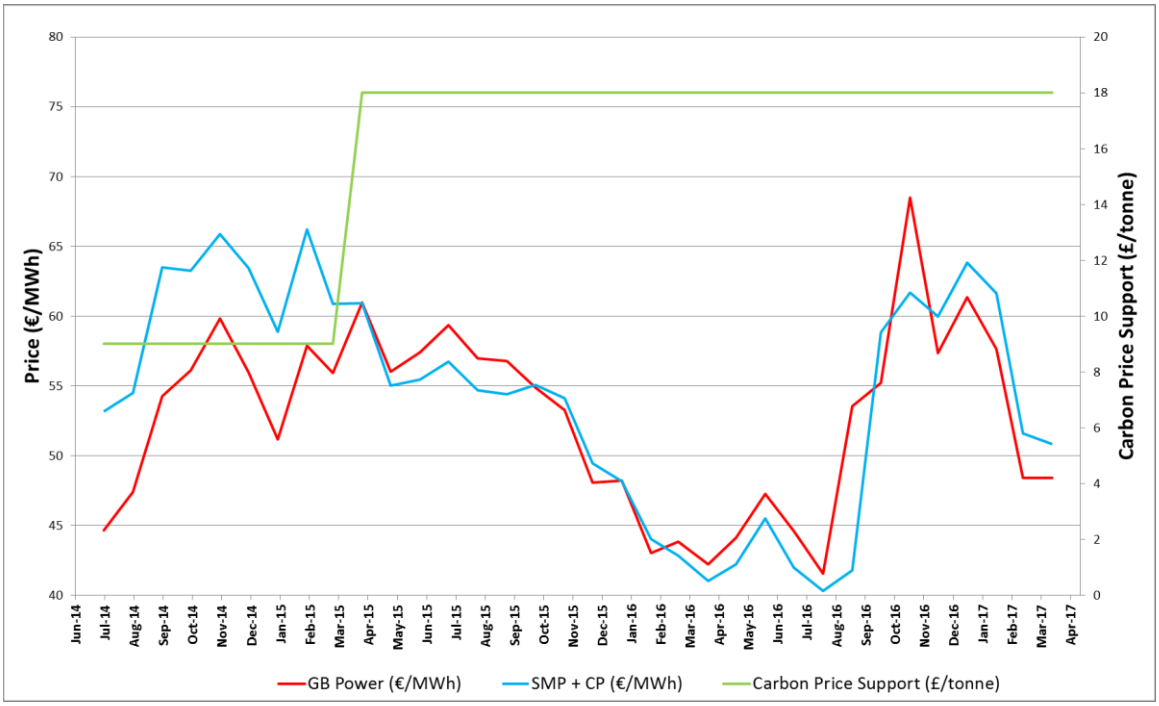

Figure 2: Price spread between SEM and GB

The TSOs have developed a number of different interconnector profiles to reflect the different flows for weekdays, weekends, high wind periods and low wind periods based on the more recent interconnector market flows. Figures 3, 4, and 5 show the flows being used for EWIC and Moyle for the SEM portion of 2017/18 tariff year. Based on the best available information at the time of this study the export capacity on Moyle is expected to be changed to 83 MW (as measured in Northern Ireland) as of the 01/11/2017 and this has been reflected in the updated Moyle flow profile in Figures 5 and 7. In I-SEM the losses on both interconnectors will be calculated differently to SEM and a linear loss equation will be used rather than a polynomial. The interconnector profiles used in the PLEXOS model for the I-SEM portion of the 2017/18 tariff year are shown in Figures 6 and 7. While the shift towards greater exports at night and lower imports during the day has the net effect of reducing DBC, the expected change to the Moyle export limit would reduce this impact somewhat and it is unclear at this point in time what the knock on effect of this will be on market interconnector flows on EWIC. Interconnector flows have been described in the Risk Factors section (Section 3.1.3) of this submission.

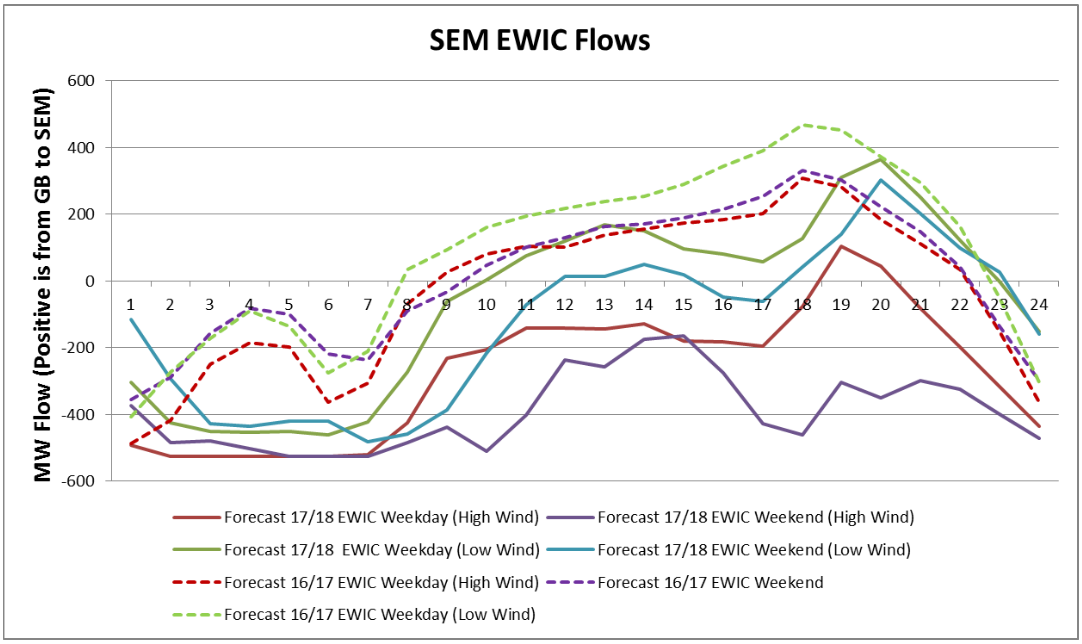

Figure 3: EWIC Profiles for SEM (01/10/2017 to 22/05/2018)

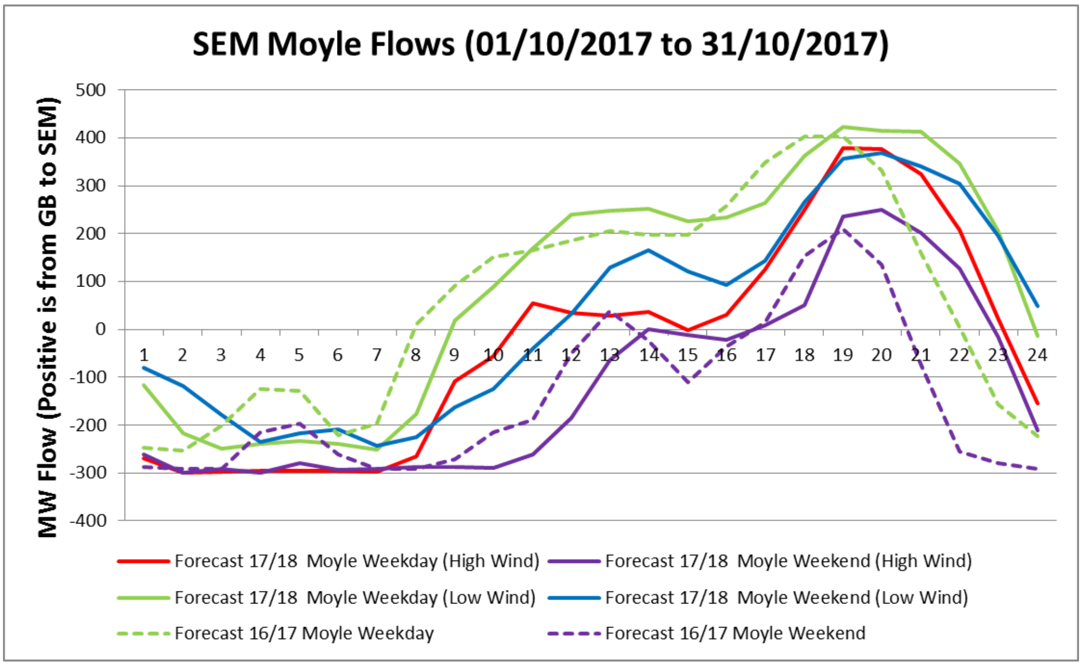

Figure 4: Moyle Profiles for SEM (01/10/2017 to 31/10/2017)

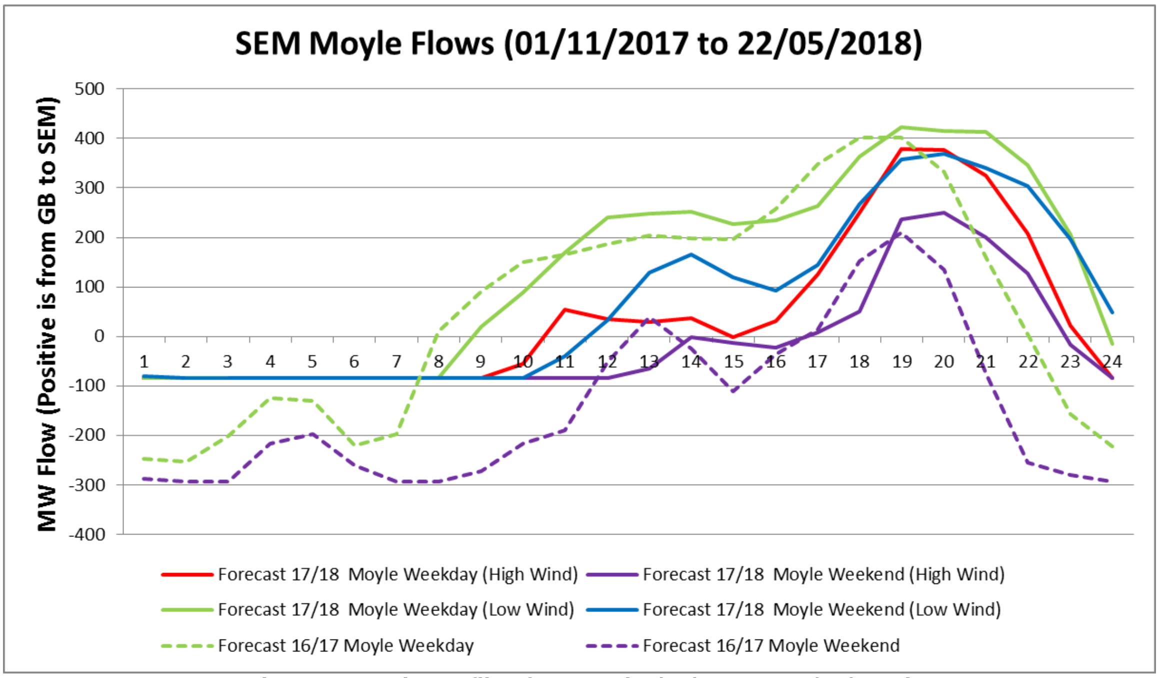

Figure 5: Moyle Profiles for SEM (01/11/2017 to 22/05/2018)

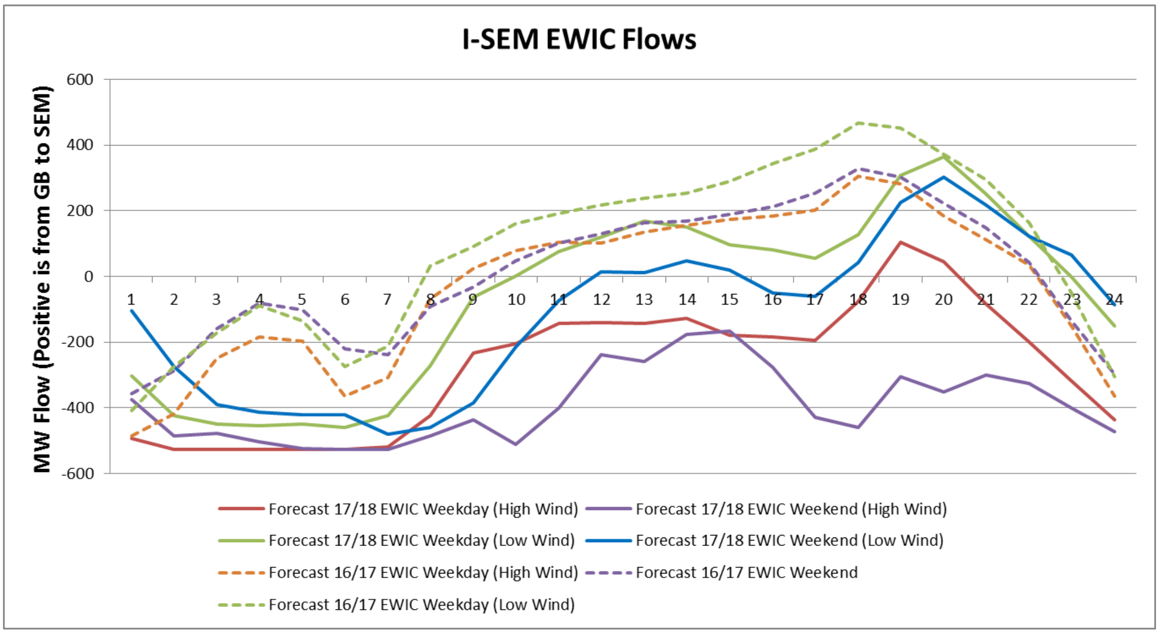

Figure 6: EWIC Profiles for I-SEM (23/05/2018 to 30/09/2018)

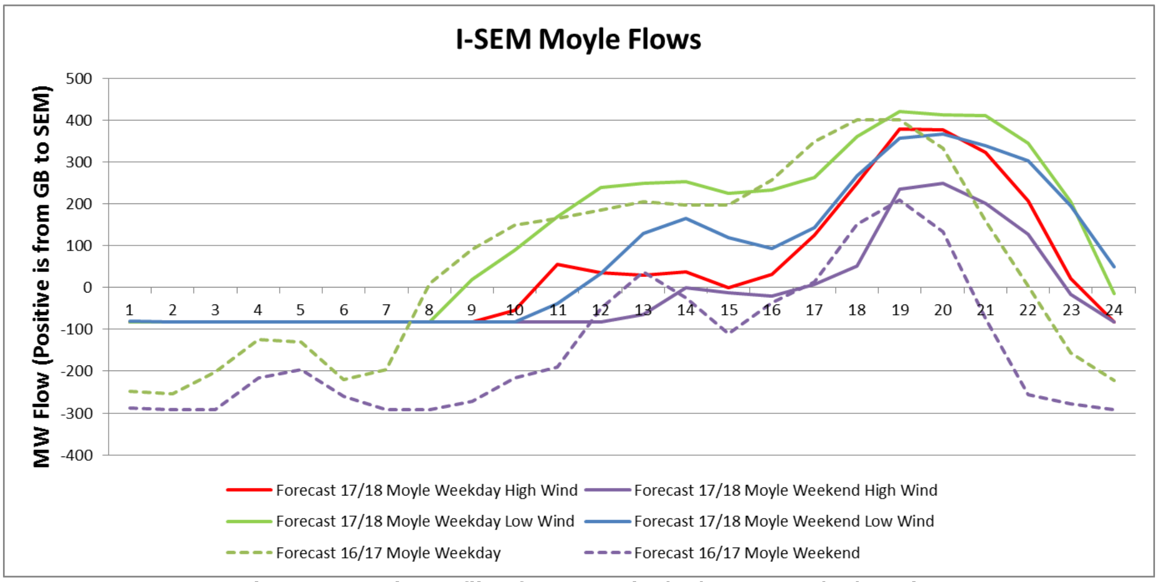

Figure 7: Moyle Profiles for I-SEM (23/05/2018 to 30/09/2018)

1.1.4 System Operator Countertrading

System Operator (SO) interconnector countertrading arrangements allow the TSOs, post SEM gate closure, to initiate changes to interconnector flows for reasons of system security or to facilitate priority dispatch generation, consistent with SEM-11-062. This activity is carried out in accordance with parameters approved by the RAs. The TSOs also introduced the initiative of countertrading for Reserve Co-optimisation in March 2014 to assist in the management of DBC, following a request from the RAs in 2014[1]. Furthermore the TSOs may, at times, incur net DBC costs due to countertrading as a result of an operational export limit on EWIC in order to maintain system security. Priority Dispatch and Reserve Co-optimisation countertrading have been enabled in the constrained model for EWIC and Moyle for the SEM portion of the year only as at the point in time of data freeze of this submission it is unclear if this type of countertrading will be possible in I-SEM. The net reduction in DBC from the revenue associated with these countertrades has been estimated in the supplementary modelling using historical prices.
Countertrading for the operational export limit on EWIC has been enabled in the constrained model for the entire tariff year, as it is assumed that the TSOs will need to continue to manage this restriction for system security in I-SEM also. The TSOs have estimated a provision for the cost of these countertrades to DBC based on historical prices in the supplementary modelling.

1.1.5 Wind Curtailment in SEM

It is assumed in the PLEXOS modelling for this submission that costs associated with the curtailment of Wind in SEM, which impacts Imperfections, will remain until I-SEM go-live on 23/05/2018.

[1]http://www.eirgridgroup.com/site-files/library/EirGrid/InformationNoteExtensionofTSOcounter-tradingfacilitiesforDBCmanagement.pdf

2. Forecast Constraint Costs

This section contains the TSOs' forecast constraint costs element of the total Imperfections revenue requirement for the tariff year 2017/18, 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 is outlined in Section 2.3.

2.1 PLEXOS Results

The forecast cost of the constraints modelled using the PLEXOS model for tariff year 2017/18 is **€140.04 million**. As mentioned previously in this submission the PLEXOS model treats both the SEM and I-SEM portions of the tariff year in the same way. Separate provisions for elements of I-SEM have been captured in the supplementary modelling described in section 2.2.2 below. This PLEXOS model portion of the forecast has increased from the forecast costs of €125.8 million for the tariff year 2016/17.

The most significant influences on forecast constraint costs in the PLEXOS model are:

- Over 20% increase in available priority dispatch generation (in particular wind generation) in the unconstrained PLEXOS model, which contributes to a lower unconstrained PLEXOS model production cost relative to the constrained PLEXOS model and an increase in forecast constraint costs;
- 6% reduction in gas prices in the PLEXOS model reduces the production costs in both the unconstrained and constrained PLEXOS models relative to the 2016/17 forecast PLEXOS models;
- Incorporating the more recent experience of lower levels of forecasted interconnector imports during the day and higher exports during the night contribute to a reduction in forecast constraint costs, as more generating units fall into merit in the unconstrained model, therefore closing the gap between the constrained and unconstrained production costs. However the reduction in Moyle export capacity from 300 MW to 83 MW (as measured in Northern Ireland) reduces this impact from 01/11/2017 until the end of the tariff year.

2.2 Supplementary Modelling Results

2.2.1 Standard Methodology

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 standard supplementary modelling for the tariff year 2017/18 is **€21.32 million**. This represents an increase of €2.89 million from the 2016/17 tariff year. Some elements of this standard supplementary modelling only apply to the SEM portion of the year whereas others apply in both.

However, the largest influencing factor on this €2.89 million increase is the SO interconnector countertrading cost. Revenue received/paid for countertraded volumes is not included in the PLEXOS modelling component, therefore a provision for this must be made in the supplementary modelling. The following is the approach used for forecasting the 2017/18 countertrading revenue:

- **Priority Dispatch:** As noted in Section 1.1.3 the level of exports from SEM to GB during the night has increased and imports from GB to SEM during the day has decreased significantly from previous years on both interconnectors. The constrained PLEXOS model for 2017/18 allows for Priority Dispatch countertrading up to 22/05/2018 and is not enabled from I-SEM go live on 23/05/2018. The export capacity on Moyle also changes to 83 MW (as measured in Northern Ireland). All these factors reduce the opportunity for Priority Dispatch countertrading in the model. The historical countertrades from 01/10/2014 to 08/04/2017 were assessed and the average €/MWh revenue from those estimated to be associated with Priority Dispatch was determined. This was then multiplied by the volume of trades estimated to be associated with Priority Dispatch from the constrained PLEXOS model. This value is a negative figure and helps reduce the forecast constraint costs;
- **Reserve Co-optimisation:** As noted in Section 1.1.3 the level of imports from GB to SEM during the day on EWIC has reduced significantly from previous years. The constrained PLEXOS model for 2017/18 allows for Reserve Co-optimisation countertrading up to 22/05/2018 and is not enabled from I-SEM go live on 23/05/2018. The opportunity for Reserve Co-optimisation countertrading in the model is therefore very limited. The historical countertrades from 01/10/2014 to 08/04/2017 were assessed and the average €/MWh revenue from those estimated to be associated with Reserve Co-optimisation was determined. This was then multiplied by the volume of trades estimated to be associated with Reserve Co-optimisation from the PLEXOS model. This value is a negative figure and helps reduce the forecast constraint costs; and
- **Export Limitations:** Due to current operational export limits on EWIC the TSOs are required to countertrade at times when market flows exceed this operational restriction and wind generation is above 1000 MW. The constrained PLEXOS model for 2017/18 allows for EWIC Export Limit countertrading for the entire tariff year. The historical countertrades from 01/10/2014 to 08/04/2017 were assessed and the average €/MWh revenue from those estimated to be associated with export limits was determined. This was then multiplied by the volume of trades estimated to be associated with the operational export limits from the constrained PLEXOS model. This value is a positive figure and increases the forecast constraint costs. Note that countertrading as a result of the operational export limits generally lowers the production cost in the constrained model, since less energy is required to be produced; however when the revenue is factored in the net effect is an increase in constraint costs. This allowance will be removed from the ex-post adjusted budget as the restriction is deemed to be within the control of the TSOs.

Similar to the 2016/17 imperfections forecast submission the TSOs have included a provision for secondary fuel start up tests for tariff year 2017/18. This provision is based on constraining on Open Cycle Gas Turbines (OCGTs) and constraining on the marginal unit during Combined Cycle Gas Turbine (CCGTs) tests for a period of time. A provision has been made for one test for all applicable units during the 2017/18 tariff year.

Finally, the forecasted €9.9 million costs of the perfect foresight effects (changes to demand and generator availability; wind predictability; and long start up and notice times) for 17/18 have decreased by just over €5 million from the 2016/17 forecast. This is largely due to the fact that these provisions are only for the SEM portion of the tariff year and due to the lower forecasted production costs in the unconstrained PLEXOS model. It is assumed these perfect foresight costs will not apply during I-SEM due to the ability of participants to trade closer to real time, thus limiting the forecast cost to €9.9 million.

2.2.2 New Considerations for 2017/18

In October 2016 a number of Northern Ireland generators included a gas product charge in their offers to the SEM, which increases DBC. It is assumed that this bidding strategy will continue for the 2017/18 tariff year. The additional associated forecast cost of €5.02 million has been included in the 2017/18 forecast, based on the Commercial Offer Data of these generators in 2016/17. The cost of the equivalent generators in Ireland is not included in the supplementary modelling as they are incorporated in the commercial offer data of the PLEXOS model.

In I-SEM an imbalance volume and cost will arise between 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. Initial studies conducted by the TSOs and provided separately to the RAs, indicate that the cost of the ramp rate differences could be up to €30 million per year. The RAs have requested that the TSOs conduct further studies and modelling to look into this cost and this is being conducted as part of a separate work stream within I-SEM. The results of these considerations are not expected for a number of months. In the absence of a decision, the estimate of €30 million per year has been included on a pro-rata basis for the I-SEM portion of the 2017/18 tariff year.

In I-SEM the scheduling process objectives set out in the TSOs' licences (published on 10 March 2017) are:

(a) minimising the cost of diverging from physical notifications;

(b) as far as practical, enabling the Ex-Ante Market to resolve energy imbalances ; and

(c) as far as practical, minimising the cost of non-energy actions by the Licensee

To achieve the cost minimisation objectives (a and c above), and meet the other objectives of satisfying security constraints and maximising priority dispatch, standard optimisation tools will at times schedule long notice units over short notice units based on cost. To achieve objective b of allowing Participants resolve energy imbalances, parameters will be applied within the optimisation to weight scheduling decisions towards shorter notice units. This is achieved by applying multipliers to the start-up costs of off-line, long notice units. This will reduce the propensity for taking early start-up actions in the scheduling process.

At the time of submission the values of the associated factors to be used in I-SEM, one being the Long Notice Adjustment Factor (LNAF), have not been determined. One of the outcomes of applying LNAFs is that they will counter the objectives of minimising costs and will lead to an increase in DBC. The potential increase to DBC depends on the magnitude of the LNAF applied and the frequency of its application. There will be greater clarity of what the LNAF related variables to be applied in I-SEM will be over the coming months through a separate SEMC consultation process on parameters for Energy Trading Arrangements.

As part of this process, the TSOs will provide a report to the RAs setting out its recommended value of LNAF based on modelling analysis. As this submission precedes the decision on these variables, an estimate of the potential impact of LNAFs has been included in this forecast as part of the supplementary modelling. The high level assumption is that the LNAF values applied will act, for the most part, as a sufficient signal for long notice generators to decrease notice time or to commit themselves through the ex-ante markets rather than the balancing market. However this will still require short notice generators to be constrained on at times and therefore a provision of €2.92m has been estimated for the I-SEM portion of the 2017/18 tariff year. This is just one potential outcome and more clarity of the potential impact to DBC of LNAFs will be clarified through the separate SEMC consultation process and will be known in advance of the decision on the 2017/18 Imperfections forecast budget.

The production cost difference in the unconstrained and constrained PLEXOS models during the I-SEM portion of the tariff year has taken an element of constraint costs in I-SEM. However, the PLEXOS models cannot model the Imbalance price and its full potential impact on DBC due to the influence of non-Bidding Code of Practice reviewed incremental and decremental costs of generators, which sets the imbalance price for non-energy actions taken by the TSO. The TSOs carried out high level analysis as to what level of additional cost this may be. A reasonably modest provision of 5% of the annual unconstrained production costs has been incorporated into the forecast for the I-SEM period of the 2017/18 tariff year i.e. €16.3 million based on an annualised cost of €45.4 million. As discussed below, this is particularly important whilst a framework for the provision of contingent capital to support additional constraint volatility in I-SEM has yet to be put in place by the RAs.

The total cost of these additional supplementary modelling considerations is €35 million.

The results of all elements of the modelling process are summarised in the table below:

Description		Forecast (€m)
PLEXOS Modelled Constraints for 12 Months		*140.04*
Perfect Foresight Effects	Changes to demand and generator availability	2.91
	Wind predictability	5.86
	Long Start-Up and Notice Times	1.13
Specific Reserve Constraints	Turlough Hill	4.34
Market Modelling Assumptions	Block Loading	0.09
	Hydro limitations & issues	0.00
System Security constraints	Capacity Testing & Performance Monitoring	1.81
Non-firm Wind Curtailment	Reduced cost to DBC of curtailing non-firm wind generation	-2.46
System Operator Interconnector Trades - Frequency Service		0.25
System Operator Interconnector Trades - Countertrading		6.76
Secondary Fuel Start Up Testing		0.63
Long Notice Adjustment Factors		2.92
Interconnector Ramp Rate Disparity		10.77
Imbalance Price Impact		16.3
Northern Ireland Gas Product Charges		5.02
Total Constraint Costs		**196.37**

2.3 Imperfections Charges – other components

In addition to the €196.37 million forecast of constraint costs above, the TSOs are setting out the following additional forecast costs for inclusion in the total revenue requirement. A further description of the individual Imperfections elements is given in Appendix 1 of this document.

Component	Forecast (€m)
Dispatch Balancing Costs	
- Constraints	**196.37**
- Uninstructed Imbalances [2]	**0.0**
- Testing Charges [3]	**0.0**
Make Whole Payments [4]	**2.7**
Net Imbalance between Energy Payments and Energy Charges [5]	**0.0**
Net Imbalance between Capacity Payments and Capacity Charges	**0.0**
Other System Charges	**0.0**
FORECAST IMPERFECTIONS REVENUE REQUIREMENT	**€199.07**

[2] *It is assumed that the constraint costs of **Uninstructed Imbalances** (for over and under generation) will, on average, be recovered by the Uninstructed Imbalance Payments for the forecast period. In the event that uninstructed output deviations occur within the tariff year, corresponding constraint costs will also arise.*

[3] *A zero provision has been made for the net contribution of **Testing Charges**, as any testing generator unit will pay Testing Charges to offset the additional constraint costs that will arise from out of merit running of other generators on the system as a result of the testing.*

[4] *The purpose of **Make Whole Payments** is to make up any difference between the total Energy Payments to a generator and the production cost of that generator on a weekly basis. Make Whole Payments are a feature of the SEM rules and are generally independent of dispatch and DBC. SEMO is responsible for administering all Make Whole Payments and they are funded by Imperfections. A provision for the Make Whole Payments for the 2017/18 tariff year is included in this submission, based on the experience of the actual Make Whole Payments from 01/10/2016 to 30/03/2017.*

[5] ***Energy Imbalances** arise from time to time due to features in the SEM rules. If Energy Imbalances do occur, they are assumed to have an equal and opposite effect on constraints and will offset any increase or decrease accordingly.*

3. Risk Factors

It is important to note there are a large number of risk factors which should be considered when assessing the appropriate level of Dispatch Balancing Costs to be included in the Imperfections revenue requirement. The main 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. This is separate to any risk of final revenues being insufficient in terms of actual payment requirements, some elements of which are included within the next section.

3.1 Specific Risks

3.1.1 Delays and Overruns of Outages

There is a significant programme of capital works scheduled to take place on the transmission system during the 2017/18 tariff year which is in turn resulting in an increase in DBC. This programme of works is in line with published Associated Transmission Reinforcements (ATRs). 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 and overrun of any outage will extend this state of reduced flexibility and may result in an increase in DBC. The outage requirements for the 2017/18 tariff year are based on best available information and there is a significant risk of delays to the start dates and overruns on these scheduled dates which are predominately outside of the control of the TSOs. The TSOs have carried out a desktop exercise of the indicative transmission outages scheduled to take place during the 2017/18 tariff year and have included the most onerous outages from a DBC perspective in PLEXOS. These outages are listed in Appendix 3 of this submission paper. The TSOs will track these in detail during the 2017/18 tariff year to investigate the impact of any slippages in scheduled dates. Furthermore the TSOs will seek to review the impact of these significant capital works as part of the ex-post review process in 2018 to determine whether they meet the assessment criteria for inclusion in the ex-post adjusted model.

3.1.2 Network Reinforcements and Additions

The PLEXOS model was built with 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 run. Examples of this include delays to network reinforcements, delays to new generator 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 be fully realised at this stage.

3.1.3 Interconnector Flows

Analysis of recent interconnector trading activity reveals that flows are not purely price-based and are predominantly imports from GB to SEM during the day and exports from

SEM to GB during the night. Participant behaviour could result in interconnector flows that differ greatly from those forecast. This, in turn, could result in constraint costs changing significantly. Interconnector flows have therefore been forecast using historical data from SEM from January and February 2017. In the last two years in the SEM market export flows have increased. However, if there is a significant change in the price difference between SEM and GB or indeed with the introduction of I-SEM, then this could significantly increase DBC. The TSOs will closely monitor the forecast flows against actual Modified Interconnector Unit Nomination (MIUNs) during the tariff year and re-forecast if there is a significant deviation.

3.1.4 Significant Bid Variations

The fuel prices used in the PLEXOS modelling process are based on industry forecasts of long term fuel prices at the time of March 2017 data freeze. 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. Wholesale fuel prices have, in general, reduced over the past number of years if fuel prices increase significantly this will increase DBC in two ways. Firstly the cost of constraining on generators will increase and secondly it could change the direction of market interconnector flows from GB to SEM. Both these factors could increase DBC.
Divergence in the relative price of fuels could also lead to an increase in Dispatch Balancing Costs. Similarly, a reduction in the relative divergence of fuel prices could lead to a reduction in 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 have included a gas product charge in their offers to the SEM, which increased DBC. The current number has been taken account in this forecast. However if any additional gas generators include a gas product charge in their offers this will increase DBC.

3.1.5 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.

3.1.6 Poor 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 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. The new capacity market in I-SEM could impact on generator availability and therefore have a knock on effect on DBC.

3.1.7 Outturn Availability

A change in practice in relation to the treatment of outturn availability of generators during transmission outages[6] could have an impact on constraint costs.

3.1.8 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.

3.1.9 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.

3.1.10 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 Bidding Code of Practice is followed. Therefore the role of the market monitor in monitoring the behaviour of participants and acting in a timely manner is important. However, in I-SEM, simple bids and offers of generators will not be bound by the same guidelines of the Bidding Code of Practice. These simple offers and bids could set the imbalance price and therefore increase DBC.

[6] 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

3.1.11 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).

3.1.12 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.

3.1.13 Modifications to the Trading and Settlement Code and I-SEM Trading and Settlement Code – Part B

All assumptions made in this submission were based on the current Market Rules as outlined in the latest version of the Trading and Settlement Code (version 18.0). The impact of future rule changes has not been considered and must be deemed a potential risk, in particular the rules around I-SEM, which were not decided on at the time of data freeze.

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 adequate, and additional security constraints may be required, resulting in an increase in constraint costs.

3.1.15 SO Interconnector Trades for Security of Supply

SO Interconnector trades may be required to maintain system security in exceptional circumstances, for instance during a capacity shortfall, where generation is insufficient to meet demand. However, due to the unpredictable and infrequent nature of their requirement, no provision is included in this submission. In the event that SO Interconnector trades are required to maintain system security on a prolonged basis, the costs of these trades may be extremely expensive and the impact on DBC can build up to significant levels very quickly, as occurred in 2008.

3.1.16 Increased Connection of Wind

There is a significant amount of wind contracted to connect during the 2017/18 tariff year. The TSOs have forecast the amount of wind which they anticipate will connect during the tariff year, based on high forecast connection rate for 2017 and 2018 and the contracted wind has been adjusted on a pro rata basis. The contracted wind due to connect is significantly higher than that used in the model. If there is an increase in rate of connection this will increase DBC. The TSOs will keep this under review.

3.1.17 Industrial Emissions Directive

In Ireland and Northern Ireland, some units are affected by the Industrial Emissions Directive (Directive 2010/75/EU of the European Parliament and the Council on industrial emissions). These units may need to purchase additional permits for emissions. The impact of this directive on combustion plants is discussed in section 3.3 of the All Island Generation Capacity Statement 2016-2025.[7]
A provision for costs arising from this has not been included in the 2017/18 forecast.

3.2 Other Risk Factors

While a number of key specific risks have been explicitly identified and outlined in Section 3.1 above, there are other factors that may contribute to unexpected and unforecast increases/decreases in DBC including exchange rate variations, operation of generators on distillate when they are assumed to run on gas in the PLEXOS model, the impacts of two-shifting generation on the reliability of the plant, significant variations in system demand and operation with significant penetration of variable generation.

As mentioned already in this submission there are many unknowns with relation to the impact of I-SEM on Imperfections. This submission has attempted to capture the main potential impacts to DBC however it is likely that other unknown risks have not been accounted for and will only become clear following the implementation of I-SEM.

Another important factor that could impact on generator bidding behaviour and market interconnector flows is the impact of Brexit. This includes fluctuations in the Euro/Sterling exchange rate and any changes in GB energy policy. The TSOs have included no additional Brexit-specific aspects.

[7] http://www.eirgridgroup.com/site-files/library/EirGrid/Generation_Capacity_Statement_20162025_FINAL.pdf

4. Total Revenue & Regulatory Cost Recovery

Given the extent of total DBC, which runs to €100's millions annually, the principle of costs being 100% pass through, as per the current arrangements, is of paramount importance. Equally, the ability to fund any revenue shortfalls, and without delay, is critical for all.

For the reasons outlined in this submission, and in the context of I-SEM, both the unpredictability and volatility of DBC is expected to rise considerably. EirGrid and SONI have advised the Regulatory Authorities that there is a need to have a regulatory framework in place which supports contingent capital requirements in I-SEM, not only for DBCs but also for potential imbalances in the other markets and timeframes. Whilst it is expected that such a framework will ultimately be put in place in advance of I-SEM go live, to date no regulatory framework has been put forward and EirGrid and SONI are awaiting input from the Regulatory Authorities as to what level of "insurance" against market shortfalls market participants can and should expect in the context of I-SEM.

To date, in the context of SEM and its associated risks, EirGrid and SONI have supported revenue mismatches through the provision of contingent capital facilities, standby debt supported by company balance sheet. Arrangements were in place whereby EirGrid and SONI would advise the Regulatory Authorities when adverse imbalances the equivalent of 50% of the available contingent capital had been reached and again at adverse imbalances equivalent to 75%.

On 14 March 2017 the Utility Regulator published a decision in respect of the SONI Price Control to cover the period 2015-2020. This decision is now the subject of appeal by SONI to the Competition and Markets Authority on the grounds that the Price Control is not financeable and that the Utility Regulator has therefore failed to exercise its duty to secure the financeability of SONI.

As the Regulatory Authorities are aware, SONI previously had in place a £12m Revolving Credit Facility to manage DBC cash-flow variations. As advised by SONI to the Utility Regulator Board on 19 January 2017, SONI has not been able to secure bank debt on the basis of the price control. Given this facility is not expected to be in place during 2017/18, and given the implications to the stability of the market in the event that SONI was not in a position to make payments in respect of any adverse movement in DBC which may arise, SONI has proposed that the £12m (€14.5m) be specifically added to the forecast revenue requirement as a tariff provision to make good this shortfall.

EirGrid and SONI recognise that, in the context of a single all island energy market, all SEM customers would be providing the associated revenues, which might be considered inequitable. This is first and foremost a matter for the Regulatory Authorities themselves however both EirGrid and SONI would like to discuss further with the Regulatory Authorities in order to ascertain the most appropriate mitigating measures.

It should be noted that even with this provision, as the debt replacement revenues would be received on a MWh profiled basis across the year, there is the potential that a cash shortfall may occur which would have to be socialised to market participants, even in the event of this adverse movement being less than £12m. This would be the case should there be adverse movement in DBC at the start of the tariff year, as has been the case in recent years. This is also something that both EirGrid and SONI would like to discuss further with the Regulatory Authorities.

As outlined, EirGrid and SONI have included a forecast cost provision of €16.3 million (as the I-SEM related portion of the €45.4 million annualised cost) due to further potential costs associated with adverse I-SEM imbalance prices. If a contingent capital framework, as referred to earlier, were to be put in place, this provision may be capable of being reduced, as it would for the €14.5 million debt replacement provision.

The corollary of excluding these provisions is that the market and its participants will see less stability and it may be necessary, in the event of adverse movement and/or shortfalls, for participants to wait for payments until such time as tariff funds have been recovered to enable payments to be made. This may not, by itself, be sufficient, particularly given the uncertainties which I-SEM brings. Therefore the TSOs must advise that, as part of the adverse imbalance notification arrangements, it may simultaneously have to request a mid-year tariff adjustment in order to ensure that an emerging deficit can be funded, without resorting to delayed or pro-rated payments. As such the TSOs request the RAs to consider what timeframes and process would be required for same and we would be happy to discuss with the Regulatory Authorities.

As is currently the case, 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. However it is not the case the provisions with regard to imbalance pricing risk and debt replacement referred to above would necessarily be removed as revenue requirements.

It should be noted, the TSOs have to date been incentivised to manage DBC (SEM-12-033) against the ex-ante forecast subject to an ex-post adjustment framework since tariff year 2012/13. It is assumed the existing framework will continue up until I-SEM go-live. It is not presumed under I-SEM until appropriately calibrated mechanisms, cognisant of the operational risks resulting from I-SEM, are agreed following discussion.

The Imperfections revenue requirement for tariff year 2017/18, is set out at a high level in the table below:

Component	Forecast (€ million)
PLEXOS Modelling	**140.04**
Supplementary Modelling	**56.33**
Make Whole Payments	**2.7**
SONI Debt Replacement	**14.5**
Total 2017/18 Forecast Imperfections Revenue Requirement	**213.57**

Appendix 1: Overview of Imperfections and Modelling Constraint Costs

1. Overview of Imperfections

The purpose of the Imperfections Charge is to recover the anticipated Dispatch Balancing Costs (less Other System Charges), Make Whole Payments, any net imbalance between Energy Payments and Energy Charges and Capacity Payments and Capacity Charges 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.

The diagram below illustrates how these are related; and how they are used to derive the SEM Imperfections Charge.

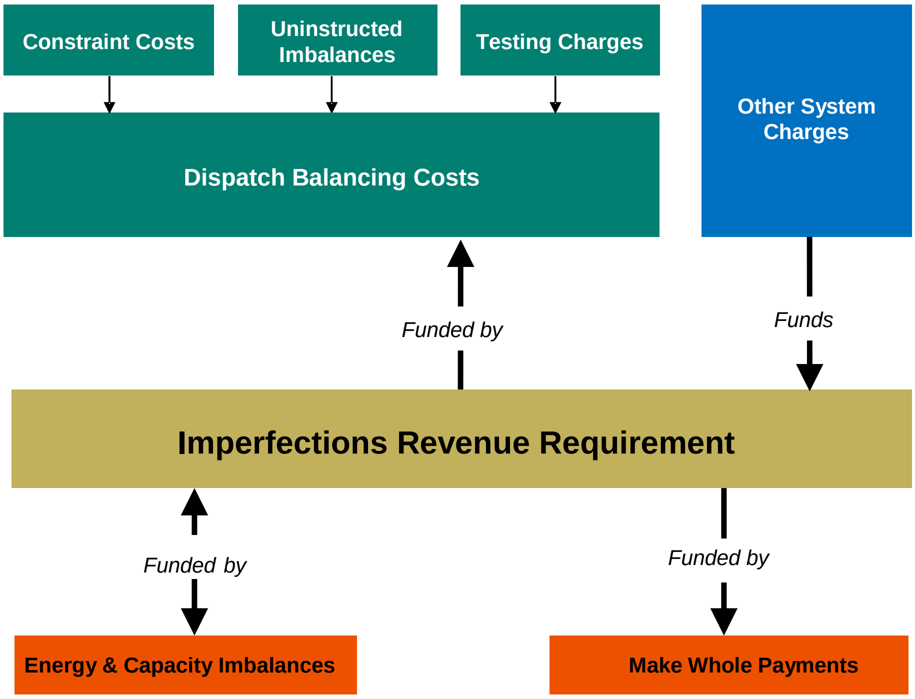

Figure 1 – Relationship between Dispatch Balancing Costs and Imperfections

The three components of Dispatch Balancing Costs, namely Constraints, Uninstructed Imbalances and Testing Charges are described in further detail in Sections 2, 3 and 4 of this Appendix respectively. Other System Charges are detailed further in Section 5. Section 6 describes Energy Imbalances and their interaction with DBC, while Section 7 discusses Make Whole Payments.

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'.

In order to balance supply and demand, a generator that is constrained off/down will always result in other generators being constrained on/up and vice versa. The units that are constrained off/down have to pay back a constraint payment (negative) and the corresponding units that are constrained on/up receive a constraint payment (positive). As the price of the constrained on/up unit is generally greater than the constrained off/down unit, there is always a net cost associated with constraints.

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 Perfect Foresight

The market schedule of generation, which is used for energy settlement, is produced after real time (*ex post*) by the market schedule using actual demand, actual wind output and known generator availabilities. However, operating the system in real-time, the TSOs do not have this perfect foresight. They must plan and operate the system to account for possible variations in these parameters.

2.2.4 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. OSC are discussed further in Section 5 of this Appendix.
- Wind and Load forecasting, which involves continually working with vendors to improve forecast accuracy.

- Introducing additional Ancillary Services which will provide a system benefit, through the new DS3 System Services[8].

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. The same PLEXOS modelling approach was used for the SEM and I-SEM portions of the 2017/18 tariff year.

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 SEM, 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 version 18.0, dated 02/10/2015.
- 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.

The following table highlights the key assumptions used in the production of the constraints in PLEXOS for the TSOs' Imperfections revenue requirements forecast. A further summary of the PLEXOS modelling and associated assumptions is provided in Appendix 2.

Subject	Assumption
Data Freeze	All input data for the PLEXOS model was frozen at 31/03/2017.
Forecast Period	The forecast period is from 01/10/2017 to 30/09/2018.
Currency	All costs are modelled in euro.

[8] http://www.eirgridgroup.com/how-the-grid-works/ds3-programme/#comp_000056cb5b8e_00000006da_78f0

Fuel and Carbon Prices	Fuel prices for 2017/18 are based on the long term fuel forecasts from Thomson-Reuters Eikon[9], the US Energy Information Administration[10] and data gathered by the TSOs. Carbon costs and Variable Operation and Maintenance Costs are also forecast.
Participant Behaviour	It is assumed that generators bid according to their short run marginal costs in SEM in line with the Bidding Code of Practice[11].
Demand Forecast	The demand is based on the 2017/18 median forecast for both Northern Ireland and Ireland from the All-island Generation Capacity Statement 2017-2026[12].
Generator Schedule Outages	2017 and 2018 maintenance outages are based on provisional outage schedules. Return Dates for the units are based on the latest available information from the Generator units as of the data freeze.
Generator Forced Outage Probabilities	Forced Outage Rates and Mean Times to Repair are based on historical data held by the TSOs.
N-1 Contingency Analysis	Principal N-1 contingencies, based on TSO operational experience, are modelled.
Transmission Scheduled and Forced Outages	A number of significant indicative scheduled transmission outages for 2017 and 2018 are modelled in PLEXOS. Forced transmission outages are not modelled.
Operating Reserve	Primary, secondary and tertiary 1 and 2 reserve requirements are modelled[13]. The output from open cycle gas turbines and peaking plant generation units is limited in the constrained model to ensure that adequate replacement reserve is maintained at all times.
Louth-Tandragee Tie-Line Transmission Limits	The Net Transfer Capacity (NTC) is modelled for the constrained schedule, which is assumed to be 300 MW N-S and 175 MW S-N. This assumption has been updated from previous years based on TSO operational experience.
Interconnector Flows	Interconnector flows with Great Britain (GB) are forecast to be predominantly imports into SEM during the day and exports into GB during the night. This reflects historical experience of flows on both interconnectors prior to the data freeze and is a best estimate of likely future flows.
Intra-Day Trading	No explicit modelling provision has been made to reflect Intra-Day trading in the PLEXOS model.

[9] https://thomsonreuterseikon.com/
[10] https://www.eia.gov/
[11] The Bidding Code of Practice - AIP-SEM-07-430
[12] http://www.eirgridgroup.com/site-files/library/EirGrid/4289_EirGrid_GenCapStatement_v9_web.pdf
[13] http://www.eirgridgroup.com/site-files/library/EirGrid/OperationalConstraintsUpdateVersion1_50_March_2017_Final.pdf

I-SEM	No explicit modelling provision has been made to reflect I-SEM in the PLEXOS model.

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.

2.5 Supplementary Modelling

As it is not possible to model all constraint cost drivers in PLEXOS, further analysis of specific factors affecting constraints was performed. This built on the PLEXOS modelling described above and looked at the impact of:

- Perfect foresight;
- Specific reserve constraints;
- Specific transmission system constraints;
- Market modelling assumptions;
- System security constraints;
- Other factors.

These are discussed, in detail, in the following sections.

2.5.1 Perfect Foresight

The market schedule is determined *ex post* with perfect knowledge of all outturn data. In contrast, the system is dispatched in real time using the best information available at that time. This disparity results in differences between the market schedule and actual dispatch, thereby increasing constraint costs. This perfect foresight effect cannot be captured in the PLEXOS modelling as the model also has perfect knowledge of all outturn data. It is assumed in this submission that constraint costs relating to perfect foresight effects will only apply to the SEM portion of tariff year 2017/18 i.e. 01/10/2017 to 22/05/2018 inclusive. The main drivers of these differences arising from perfect foresight are described as follows:

2.5.1.1 Changes to Demand and Generator Availability

Since it is calculated *ex post*, the Unconstrained Unit Commitment (UUC) (initial) market schedule[14] has the benefit of perfect foresight of changes in demand and generator availability. The TSOs do not have this advantage and must respond to such changes as and when they happen.

Following the tripping of a generator, the TSO must activate reserves and will typically have to replace the lost generation using fast start plant e.g. peaking units, at a significant cost. Other System Charges, such as Trip and Short-Notice Declaration charges, are levied on generators who fail to provide necessary services to the system[15]. OSC therefore act to take account of the immediate, short-term costs incurred from these events. The monies paid by generators are then used to offset the DBC costs incurred.

However, in addition to replacing lost generation capacity immediately after the event, the TSOs are also unaware of how long the plant will be unavailable for in real time operations. This may result in re-dispatching a number of generating units to ensure that there is adequate capacity to meet demand and reserve requirements where the expected return of the generator is uncertain, The UUC market schedule on the other hand, since it knows that the generator will trip, can schedule the most economic replacement plant in anticipation of the tripping (e.g. by starting another unit in the market several hours before the tripping). It also has perfect knowledge of the duration of the unavailability and can schedule plant in as optimal a manner as possible. This continuous information asymmetry results in considerable constraint costs over the year.

2.5.1.2 Impact of Wind Predictability

Wind is inherently a variable resource. The UUC market schedule, with perfect foresight, can schedule the most economic generation to balance this variability as it knows exactly the level of wind output in every period. The TSO, on the other hand, since it is not always aware of the timing or extent of these variations, must balance them using a combination of part-loaded plant and more expensive fast-start plant. This less optimal schedule will cause an increase in constraint costs.

2.5.1.3 Long Start-Up and Notice Times, Lack of Flexible Plant

The generation portfolio has changed in recent years due to a number of plant closures, and the fact that new build has tended to be larger, less flexible units. This deficit of mid-merit units that can start with relatively short notice periods has resulted in a reduction in

[14] In the Trading and Settlement Code, the UUC is referred to as the MSP software.
[15] http://www.soni.ltd.uk/media/documents/Operations/Ancillary-Services/Harmonised%20OSC%20Methodology%20Statement%201516.pdf

portfolio flexibility for reacting to unexpected changes in generation and demand. Previously, when mid-merit units were available, uncertainty over generation, wind and load could be managed within 1 to 2 hours using these flexible mid-merit generator units. Any potential capacity shortages due to generation, wind and load uncertainty in the near future require commitment decisions to be made a number of hours in advance due to the long notice periods required by the generator units available to meet these shortages.
These commitment decisions are made to mitigate against the risk of a capacity shortage and to ensure that sufficient replacement reserve is maintained to deal with any further changes to unit availability, interconnector scheduled flows or forecast demand or wind. Availability of generation with shorter notice times and/or greater flexibility would mean that such commitment decisions could be made nearer to real-time and with better information. With higher levels of wind and interconnection, managing the system in real time with the current generation portfolio remains a challenge.

2.5.2 Specific Transmission System Constraints

Transmission line limits are modelled in PLEXOS. As in previous years there were some other transmission system constraints which it is not possible to model in PLEXOS and for which specific provision had to be made. A brief description of these is given in the following section.

2.5.2.1 Limited Transmission Scheduled Outages in PLEXOS

Transmission outages can result in additional transmission constraints. These additional constraints may include requirements to run out-of-merit generation, restrictions on the maximum tie-line flow and localised export constraints. This year a number of the significant transmission outages have been incorporated into the PLEXOS model based on the indicative transmission outage programme as of the data freeze date.
No specific provision for other expected transmission outages has been included in this submission.

It should be noted that the principal, most onerous N-1 contingencies were included in the PLEXOS model. It was assumed that other contingencies had a negligible effect on constraint costs or could be solved post contingency.

2.5.2.2 Forced Transmission Outages

Forced transmission outages can result in additional transmission constraints, through requirements for out-of-merit generation, restrictions on the maximum tie-line flow or localised export constraints. As such, the outage of certain items on the transmission system can potentially increase DBC significantly. However, due to the unpredictable nature of such outages, it is not possible to calculate a specific provision for this submission or to include them in the PLEXOS model. As such, forced transmission outages are identified as a risk rather than an explicit cost.

2.5.3 Specific Reserve Constraints

PLEXOS includes requirements for primary, secondary and tertiary operating reserves. In addition, regulation and replacement reserve requirements are also met through the constraints in the PLEXOS model.

Turlough Hill is a key source of spinning reserve. However, while reserve provision by the units is modelled in PLEXOS, it is not possible to model all of the operating modes. In particular, the minimum generation mode allows provision of reserve at very low loads but at a much lower efficiency than normal operation. This efficiency reduction effectively reduces the total energy available in the dispatch. This energy must be replaced (by the marginal plant), resulting in additional constraint costs over the day.

2.5.4 Market Modelling Assumptions

The UUC market schedule software makes a number of modelling assumptions and simplifications that are necessary to allow it to generate robust solutions in a reasonable length of time. PLEXOS also makes similar modelling assumptions. These simplifications can result in infeasible schedules that would be impossible in reality, even in the absence of any transmission system constraints. The consequence is that additional constraint costs will arise.

2.5.4.1 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 the UUC market schedule, resulting in out-of-merit running and hence constraint costs. A provision 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.

2.5.5 System Security

2.5.5.1 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.

With increasing amounts of base-load thermal and wind generation, there will be more instances of out-of-merit generators not being required to run. 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, but taking into account additional starts assumed under the Long Start-Up and Notice Times provision.

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.

2.5.6 Treatment of Wind with Non-Firm Access in PLEXOS

The PLEXOS model does not differentiate between wind generation units with firm and non-firm access. In recognition of this, a provision has been made to reflect the effect of wind with non-firm access dispatched down over the year. Dispatching down of wind generation normally represents a cost in terms of constraints as in order to maintain supply-demand balance, price making generation has to be dispatched to meet demand which was met in the market schedule by price taking wind generation. However, with the implementation of a revision to SEM rules[16] around the treatment of wind generation with non-firm access, dispatching down wind with non-firm access will not result in this cost in terms of constraints, as any dispatched down wind with non-firm access will not be scheduled in SEM.

A negative provision is included in this submission to offset the over-estimation of the cost of dispatched-down wind in the PLEXOS model due to a portion of that wind generation having non-firm access. This has been applied for the SEM portion of the tariff year only i.e. 01/10/2017 to 22/05/2018 inclusive.

2.5.7 SO Interconnector Trades

An explicit provision is made for constraint costs arising from SO Interconnector Trades for the Low and High Frequency Service on Moyle and on EWIC, in line with previous years. This has been applied for the entire 2017/18 tariff year.

SO interconnector countertrading arrangements allow the TSOs, post SEM gate closure, to initiate changes to interconnector flows for reasons of system security, to facilitate priority dispatch generation, as directed by SEM-11-062 or for Reserve Co-optimisation i.e. reduce the interconnectors as the Largest Single Infeed (LSI).
For the SEM potion of the 2017/18 tariff year the flows for both EWIC and Moyle were compared between the constrained and unconstrained PLEXOS models. The volumes of countertrading were then, based on assumptions, divided out to Priority Dispatch, Reserve Co-optimisation and export limit countertrading on EWIC and Priority Dispatch for Moyle. The estimated revenue received from 01/10/2014 to 08/04/2017 was used to determine an average €/MWh for these countertrades to determine the revenue which would be received.
The same process was applied to estimate the cost to DBC from EWIC export limit countertrades for the I-SM portion of the year also.

This results in a net positive provision for SO Interconnector Trades in this submission.

[16]http://www.sem-o.com/MarketDevelopment/ModificationDocuments/110607%20SEM%20C%20Decision%20on%20Mod_43_10.pdf

2.5.8 Secondary Fuel Start Up 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 2017/18 tariff year for all applicable units.

3. Uninstructed Imbalances

3.1 Overview of Uninstructed Imbalances

Uninstructed Imbalances [17] and constraint costs are related, with uninstructed imbalances having a direct effect on constraints costs, as TSOs re-dispatch generators to counteract the impact of uninstructed imbalances on the system.

All dispatchable generation is required to follow instructions from the control centres within practical limits to ensure the safe and secure operation of the power system. Deviation of a generating unit from its dispatch instruction will have a direct impact on system frequency and on the reserve available to the TSOs for frequency control.

Over-generation by a generating unit may result in a need for the TSOs to instruct other generating units down from their dispatched levels to lower levels in order to balance supply and demand. Significant over-generation can necessitate dispatching a generator off load to compensate. Under-generation by a generating unit may result in the need to instruct other generating units up from their dispatched levels to higher levels. In the event of unexpected or large under-generation by a generator the TSOs must act in a quick and decisive manner to restore appropriate system balance and reserve targets. This will generally necessitate dispatching on quick-start generators.

Uninstructed deviations therefore lead to increased constraint costs as the TSOs re-dispatch other generation at short notice. In SEM, the uninstructed imbalance mechanism provides the economic signals to ensure generators follow dispatch instructions and any net accrual of uninstructed imbalance payments offset the constraint costs that the uninstructed deviations gave rise to.

3.2 Forecasting Uninstructed Imbalances

It is assumed that the constraint costs of Uninstructed Imbalances (for over and under generation) will, on average, be recovered by the Uninstructed Imbalance payments for the forecast period.

Any incomings or outgoings are offset by the corresponding constraint costs due to action required by TSOs in response to Uninstructed Imbalances. As in previous submissions, an assumption is made that the current Uninstructed Imbalance mechanism sends the correct signals to generators and that all generators are fully compliant with dispatch instructions. As such, no provision for the constraint costs that would arise due to uninstructed deviations is included in this submission and a zero provision for Uninstructed Imbalances is forecast. In the event that uninstructed deviations occur within the tariff year, corresponding constraint costs will also arise. It is assumed in this submission that the Uninstructed Imbalance parameters will remain the same for the I-SEM portion of the 2017/18 tariff year and will continue to provide the economic signals to ensure generators follow dispatch instructions.

[17] Uninstructed Imbalances occur when there is a difference between a Generator Unit's Dispatch Quantity and its Actual Output.

4. Testing Charges

The testing of generator units results in additional operating costs to the system in order to maintain system security. As a testing generator unit typically poses a higher risk of tripping, additional operating reserve will be required to ensure that system security is not compromised, which will give rise to increased constraint costs. The TSOs may need to commit extra units to ensure sufficient fast-acting units are available for dispatch to provide a rapid response to changes from the testing generator unit's scheduled output and to ensure that the system would remain within normal security standards following the loss of the generator unit under test. Additional constraint costs will arise whenever there is a requirement to increase the existing reserve requirement above the normal level on the system.

In SEM, Testing Charges are applied to generator units that are granted under test status.
The actual costs incurred that may be attributed to a testing generator unit are volatile and variable. As such, generators pay for the costs of testing based on an agreed schedule of charges. The Testing Tariffs, which are used to calculate the Testing Charges for each unit, have been set at a level that should, on average, recover the additional costs imposed on the power system during generator testing.

A zero provision has been made for the net contribution of Testing Charges, as any testing generator unit will pay Testing Charges to offset the additional constraint costs that will arise from out of merit running of other generators on the system as a result of the testing. This assumption applies to both the SEM and I-SEM portions of the 2017/18 tariff year.

5. Other System Charges

Other System Charges (OSC) are levied on generators whose failure to provide necessary services to the system lead to higher Dispatch Balancing Costs and Ancillary Service Costs. OSC include charges for generator units which trip or make downward re-declarations of availability at short notice. Generator Performance Incentive (GPI) charges were harmonised between Ireland and Northern Ireland with the Harmonisation of Ancillary Service & Other System Charges "Go-live" on the 01/02/2010.

These charges are specified in the Charging Statements separately approved by the Regulatory Authorities (RAs) in Ireland and Northern Ireland. The arrangements are defined in both jurisdictions through the Other System Charges policies, the Charging Statements and the Other System Charges Methodology Statement.

As DBC and generator performance are intrinsically linked, Other System Charges are netted off DBC in SEM[18]. Since the introduction of Other System Charges, the performance of generators on the system has improved. It is assumed in this submission that generators are compliant with Grid Code and no charges are recovered through Other System Charges. As any deviation from this assumption will result in an increase in DBC, any monies recovered through Other System Charges will net off the resultant costs to the system in DBC. This assumption applies to the entire 2017/18 tariff year.

There are a number of reasons for having a zero provision for Other System Charges:

1. The TSOs assume all generators to be grid code compliant in the imperfections forecasting process. As Other System Charges are event based, it would be inappropriate to forecast them and could be deemed discriminatory;
2. If a generator unit trips or re-declares their availability down at short notice they are required to pay charges to compensate for not supplying the necessary services to the system. Such events would result in an increase in DBC. The TSOs assume that any revenue generated from Other System Charges covers some of the immediate short-term costs that arise as a result of these events; and
3. There is an additional cost associated with the unexpected loss of generation as the exact time the unit returns to service may be unknown and as such the TSOs may need to dispatch other generation to meet demand and reserve requirements. The market schedule, however, has perfect foresight of the unit trip and its outage duration. Therefore it can optimise the generation portfolio around this, for example starting another unit several hours before the trip. This disparity between the market and dispatch schedules result in an increase in DBC. The TSO's have included a provision for this in their forecasting submission under the subheading Perfect Foresight Effects. This is in line with previous years' submissions.

[18] Trading and Settlement Code V18.0, clause 4.155: "The purpose of the Imperfections Charge is to recover the anticipated Dispatch Balancing Costs (less Other System Charges), Make Whole Payments, any net imbalance between Energy Payments and Energy Charges and Capacity Payments and Capacity Charges over the Year, with adjustments for previous Years as appropriate."

6. Energy Imbalances

A continuous balance between system generation and system demand plus losses is required to maintain a secure system. As a result of this, the sum of the loss adjusted Market Schedule Quantities (MSQs) on which generators are paid Energy Payments should equal the loss adjusted net demand on which suppliers pay Energy Charges.

Energy Imbalances occur in SEM in the event that the sum of Energy Payments to generators does not equal the sum of Energy Charges to suppliers. There is an inherent link between Energy Imbalances and Constraints. An Energy Imbalance will generally impact Constraint costs in the opposite direction, artificially increasing or decreasing the total Constraint Costs. For example, Energy Payments will exceed Energy Charges if the sum of the MSQs is greater than the net demand and will result in an Energy Imbalance out of SEM (i.e. more paid out than recovered). In reality, in this example the system would have been balanced and the dispatch of generators will equal actual demand (plus losses) on the system. Constraints are calculated as the difference between the MSQs and the dispatch of each generator. When the sum of the MSQs exceeds the sum of dispatched generation, it will result in a net reduction in the system Constraint costs, as more generators will appear constrained down/off than will be constrained on/up.

Energy Imbalances arise from time to time due to features in the SEM rules. For example, if the Dispatch Quantity of a testing generator unit deviates from the Nomination Profile submitted to SEM, which could occur either due to events that occur during the testing or for system security reasons, an energy imbalance may arise. In this submission, it is assumed no Energy Imbalances will arise and no provision in terms of Energy Imbalances with corresponding additional/reduced Constraints is included. If Energy Imbalances do occur, they are assumed to have an equal and opposite effect on constraints and will offset any increase or decrease accordingly. This assumption applies to the entire 2017/18 tariff year.

7. Make Whole Payments

The purpose of Make Whole Payments is to make up any difference between the total Energy Payments to a generator and the production cost of that generator on a weekly basis. As such, Make Whole Payments are a feature of the SEM rules and are generally independent of dispatch and DBC. SEMO is responsible for administering all Make Whole Payments and they are funded by Imperfections. Make Whole Payments will also be a feature in I-SEM. An additional element known as a Fixed Cost Payment will be included in I-SEM. A provision for the Make Whole Payments for the entire 2017/18 tariff year is included in this submission, based on the experience of actual outturn from 01/10/2016 to 31/03/17.

Appendix 2: PLEXOS Modelling Assumptions

PLEXOS is used by the TSOs to forecast constraint costs. PLEXOS is a production costing 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 2017/18 are defined in €/GJ based on the long term fuel forecasts from Thomson-Reuters Eikon[19] 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 01/10/2017 to 30/09/2018
Data Freeze	The input data for the PLEXOS model was frozen on 31/03/2017
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.
PLEXOS Version	7.3 Revision 4
Model Reference	DBC 1718 v1.0

Demand

Feature	Assumptions
Regional Load	NI total load and IE total load are represented using individual

[19] https://thomsonreuterseikon.com/

Feature	Assumptions
	hourly load profiles for each jurisdiction. Both profiles are at the generated exported level and include transmission and distribution losses and demand to be met by wind.
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 2017-2026[20]. Historical analysis on generators' declared availability was carried out and some units seasonal ratings were adjusted based on this.
Production Costs	Calculated through PLEXOS using the Regulatory Authorities' publicly available dataset: 2016/17 Validated SEM Generator Data Parameters[21]. 1. Fuel cost (€/GJ) – forecasted for 2016/17 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. 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.
Generation Constraints (TOD)	Based on the data in the 2016/17 Validated SEM Generator Data Parameters[21] 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 The capping of the Maximum Generation based on the contracted Maximum Export Capacity (MEC) in Ireland per the CER Decision[22] was not implemented due to this decision being deferred.
Scheduled Outages	Draft outage schedules are used for 2017 and 2018

[20] http://www.eirgridgroup.com/site-files/library/EirGrid/4289_EirGrid_GenCapStatement_v9_web.pdf
[21] https://www.semcommittee.com/news-centre/baringa-sem-plexos-forecast-model-2016-17
[22] CER/14/047 – Decision on Installed Capacity Cap

Feature	Assumptions
	maintenance outages
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 2016/17 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.
Wind Generation	Wind generation resources are based on MW currently installed plus an anticipated rate of connection based on the All Island Renewable Connection Report 36 Month Forecast (Q4 2013)[23]. This is based on 2607 MW already installed in Ireland and 672 MW in Northern Ireland. For the 2017/18 tariff year the high all-island connection rate from the All Island Renewable Connection Report 36 Month Forecast (Q4 2013) which was 670 MW / year.
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%.
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 Great Britain (GB) are forecast to be predominantly imports into SEM during the day and exports into GB during the night. This reflects historical experience of flows on both interconnectors prior to the data freeze and is a best estimate of likely future flows. It is expected that the export capacity on Moyle will be 83 MW as of 01/11/2017.
Solar Generation	At the time of data freeze 31/03/2017, three solar generators were due to connect to the electricity network in Northern Ireland by 01/10/2017, providing just over 77 MW in total. These generators have been included as price takers in the model.
Non-Synchronous	System Non-Synchronous Penetration (SNSP) is set at 60% in

[23] http://www.eirgridgroup.com/site-files/library/EirGrid/All_Island_Renewable_Connection_Report_36_Month_Forecast__(Q4_2013).pdf

Feature	Assumptions
Generation	the constrained PLEXOS model.

Transmission

Feature	Assumptions
Transmission Data	The transmission system input to the model is based on data held by the TSOs.
Transmission Constraints	The transmission system is only represented in the 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.
Tie-Line	The North-South tie-line is not represented in the unconstrained SEM-GB model. The Net Transfer Capacity (NTC) is modelled in the constrained schedule, with flow limits set to 300 MW N-S and 175 MW S-N.
Interconnection	The Moyle Interconnector and EWIC are modelled.
Forced Outages	No forced outages are modelled on the transmission network.
Scheduled Outages	Major transmission outages likely to take place in the tariff year and which would impact on constraints are modelled.

Ancillary Services

Feature	Assumptions
Operating Reserve	Primary, Secondary, Tertiary 1 and 2, and Replacement Reserve requirements are modelled. Negative Reserve at night of 100MW in IE and 50MW in NI is 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[25]
Static Sources	Static reserve provided by STAR (an interruptible load scheme) is modelled. It is assumed that 43 MW of static reserve is available from 07:00 to 00:00. The STAR provision is reduced to 18 MW between 12:00 on 22/12/2017 to 02/01/2018. Static reserve will be available on Moyle if there is sufficient unused capacity available, up to a maximum of 49 MW in Northern Ireland (the reserve is 50 MW, however this is measured in Great Britain). Static reserve will be available on EWIC if there is sufficient unused capacity available, up to a maximum of 70 MW in Ireland (the reserve is 75 MW, however this is measured in Great Britain). Note that during outages of EWIC it is assumed that 49 MW of additional static reserve will be available on Moyle i.e. up to 98 MW of static reserve from Moyle (as measured in Northern Ireland).

[25] http://www.eirgridgroup.com/site-files/library/EirGrid/OperationalConstraintsUpdateVersion1_50_March_2017_Final.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.

Outage	Start Date	End Date
Dunstown Moneypoint 400kV	02/10/2017	27/10/2017
Moneypoint T4003	02/10/2017	27/10/2017
Corderry Garvagh 110 kV feeder	02/10/2017	15/10/2017
Castlebar 110 kV A2	07/08/2017	30/10/2017
Arigna T – Carrick on Shannon 110 kV feeder	16/10/2017	27/10/2017
Ardnacrusha Drumline 110kV	16/10/2017	27/10/2017
Kilkenny 110kV A1 (Kilkenny-Kellis switched out)	05/02/2018	11/06/2018
Kilkenny 110kV A2 A1 (Kilkenny-Great Island switched out)	05/02/2018	11/06/2018
Maynooth-Shannonbridge 220 kV feeder	05/03/2018	23/03/2018
Flagford - Louth 220 kV feeder (220 kV A2/B2 side)	02/04/2018	22/06/2018
CASTLEBAR 110 kV A1	05/03/2018	25/05/2018
Aghada 220kV A1/B1 (Generators AT1, AT2 and AT4 on outage)	07/05/2018	22/06/2018
Killonan Tarbert 220kV	05/03/2018	20/07/2018
Aghada Longpoint 220kV	07/05/2018	29/06/2018
Corduff - Finglas 2	04/06/2018	17/07/2018
Woodland - Clonee 220 kV	04/06/2018	13/07/2018
Maynooth - Woodland 220 kV feeder	05/03/2018	01/06/2018
Moneypoint - Oldstreet 400kV line	02/07/2018	19/10/2018
Moneypoint T4001	02/07/2018	19/10/2018
Cullenagh Knockraha 220kV	02/07/2018	07/09/2018
COS A1	04/06/2018	27/07/2018
COS-ARVA	04/06/2018	27/07/2018
Oldstreet-Woodland 400 kV feeder	02/07/2018	10/08/2018
Aghada T2011/12	02/07/2018	24/08/2018
Finglas - Shellybanks	03/09/2018	09/10/2018
Carrickmines - Poolbeg	05/03/2018	17/08/2018
Flagford Sligo	17/09/2018	12/10/2018
Cloon Lanesboro 110 kV feeder	20/08/2018	07/09/2018

Appendix 4: N-1's

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

Loss of Aghada-Knockraha 220kV 1
Loss of Aghada-Knockraha 220kV 2
Loss of Ballyvouskil Clashavoon 220
Loss of Cashla-Flagford 220kV
Loss of Cashla-Prospect 220kV
Loss of Cashla-Tynagh 220kV
Loss of CKM-Dunstown 220kV
Loss of CKM-Irishtown 220kV
Loss of Clashavoon Knockraha
Loss of Cullenagh-Great Island 220kV
Loss of Cullenagh-Knockraha 220kV
Loss of Dunstown-Maynooth 220kV
Loss of Flagford-Louth 220kV
Loss of Flagford-Srananagh 220kV
Loss of GI-Kellis 220kV
Loss of Gorman-Louth 220kV
Loss of Gorman-Maynooth 220kV
Loss of Inch-Irishtown 220kV
Loss of Killonan Tarbert
Loss of Knockraha-Raffeen 220kV
Loss of Louth-Woodland 220kV
Loss of Maynooth-Woodland 220kV
Loss of Moneypoint-Prospect 220kV
Loss of Poolbeg Reactor
Loss of Prospect-Tarbert 220kV
Loss of Ardnacrusha-Singland 110 kV
Loss of Ardna-Lim 110kV
Loss of Arigna Tee-Carrick-on-Shannon 110 kV
Loss of Bellacorick-Castlebar 110 kV
Loss of Binbane-CF
Loss of Cahir-Doon 110kV
loss of CF Clogher 110kV
Loss of CF-Corraclassy
Loss of CF-Srannagh 1 110kV
Loss of Clogher-Golagh Tee 110 kV

loss of Clonkeen Clashavoon
Loss of Corduff-Ryebrook 110 kV
Loss of Corraclassy Gortawee 110kV
Loss of Cullenagh-Waterford 110 kV
loss of Cushaling Portlaoise 110 kV
Loss of Flagford-Sligo 110kV
Loss of Marina Trabeg 110kV 1
Loss of Marina Trabeg 110kV 2
Loss of Raffeen-Trabeg 110kV 1
Loss of Raffeen-Trabeg 110kV 2
Loss of Shannonbridge-Ikerrin
Loss of Sligo-SRA 1 110kV
Loss of Tarbert-Trien 110kV
loss of Clashavoon trafo
Loss of GI 220-110 1
Loss of GI 220-110 2
Loss of Moneypoint-Dunstown 400 kV
Loss of Moneypoint-Oldstreet 400 kV
Loss of Oldstreet-Woodland 400 kV
Loss of COLE1- to COOL1- 110 kV
Loss of COLE1- to LIMA1- 110 kV
Loss of COOL1- to KILL1-CL 110 kV
Loss of KELS1- to RASH1- 110kV
Loss of OMAH1- to STRA1- 110 kV
Loss of Ballyvouskill-Ballynahulla 220 kV
Loss of Coolkeeragh-Magherafelt 275 kV Double Circ
Loss of Dungannon-Tamnamore 110kV
Loss of Dungarvan-KRA 110kV
Loss of Gorman-Navan 110 kV 3
Loss of Killoan-Singland 110 kV
Loss of Knockanure-Tarbert 220 kV
Loss of Omagh-Dungannon 110kV

Appendix 5: Glossary

AGU	Aggregated Generator Unit
ATR	Associated Transmission Reinforcements
CCGT	Combined Cycle Gas Turbine
CER	Commission for Energy Regulation
DBC	Dispatch Balancing Costs
DSU	Demand Side Unit
EWIC	East West Interconnector
GB	Great Britain
GPI	Generator Performance Incentive
HILP	High Impact Low Probability
I-SEM	Integrated Single Electricity Market
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
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
TSO	Transmission System Operator
TUoS	Transmission Use of System
UUC	Unconstrained Unit Commitment
UREGNI	Utility Regulator for Northern Ireland
VOM	Variable Operation and Maintenance