Imperfections Cost Incentive

Tariff Year: 1st October 2017 to 30th September 2018

26th June 2019

EIRGRID SONI

Executive Summary

Dispatch Balancing Costs (DBC) are an inherent feature of the SEM design and arise due to the difference between the ex-post market schedule and the real-time dispatch. These costs are levied on Suppliers through the Imperfections Charge. EirGrid and SONI, as Transmission System Operators (TSOs), are responsible for managing DBC through efficient dispatch of generation, while still maintaining a secure electricity system.

A process to incentivise the TSOs to reduce DBC was announced by the Regulatory Authorities (RAs) in June 2012. A set of targets, dead-bands, payments and penalties were established to provide benefits to the all-island customer through the reduction of Imperfections Costs. Since the establishment of the incentive process the TSOs, through the introduction of operational initiatives, have reduced Imperfection Costs (excluding Make Whole Payments) by €117.1 million as follows:

- 2012/13 €3 million
- 2013/14 €52.4 million
- 2014/15 €17.2 million
- 2015/16 €10.5 million
- 2016/17 €15.3 million
- 2017/18 €18.8 million

These savings are not only realised in the year in question but also create savings in the following years as they become normal operational standards. This submission by the TSOs sets out the actual outturn and compares this with an ex-post adjusted Imperfections revenue requirement for the 2017/18 tariff year. This forms the basis of the calculation of an incentive payment.

The components of the outturn Imperfections Costs that are subject to the incentive mechanism are: Dispatch Balancing Costs (DBC), System Operator (SO) Trades, Energy Imbalances, and Other System Charges with the primary component being DBC. In the ex-post review process, material factors that are outside the control of the TSO, and fulfil a set of predefined criteria, are subject to an ex-post adjustment mechanism. This involves an update to the models and calculations carried out for the original Imperfections revenue requirement with actual data. As part of the ex-post adjustment process, various elements were considered material (see Section 3.1), including general refinements to the model and actual data changes.

The outturn Imperfections Costs incurred over the Tariff Year 2017/18 were €184.3 million; €18.8 million lower than the ex-post adjusted Imperfections revenue requirement. This saving is consistent with the initiatives and focus applied during the year by the TSOs, in particular (but not limited to): removal and amendments to Dublin generation rules and removal of Kilroot generation rules.

The savings made by the TSOs during the Tariff Year 2017/18 meet the requirements for receiving an incentive payment of €0.354 million.

1. Introduction

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

The submission is for the period from 01/10/2017 to 30/09/2018 inclusive, referred to as the Tariff Year 2017/18. Actual outturn was measured against an ex-post adjusted Imperfections revenue requirement referred to as the ex-post adjusted baseline. The original Imperfections revenue requirement is referred to as the submitted forecast. The components of the outturn Imperfections Costs that are subject to the incentive mechanism are: Dispatch Balancing Costs (DBC), System Operator (SO) Trades, Energy Imbalances and Other System Charges, with the primary component being DBC.

The Single Electricity Market Committee (SEMC) introduced an incentive mechanism on the TSOs to reduce all-island Imperfections Costs from the period 1 October 2012 onwards. The incentive mechanism takes account the current industry structure and the degree of control which the TSOs have on the cost drivers. The incentive mechanism includes an ex-post adjustment mechanism to ensure the protection of both the TSOs and all-island customers from potential windfall gains or losses, by removing some of the risk for events outside of the TSOs' control. Since the introduction of the incentive process the TSOs, through the introduction of operational initiatives, have reduced Imperfection Costs (excluding Make Whole Payments) by €98.4 million (2012/13: €3m, 2013/14: €52.4m, 2014/15: €17.2m, 2015/16: €10.5m, 2016/17: €15.3, 2017/18: €18.8m). These savings are not only realised in the year in question but also create savings in the following years as they become normal operational standards.

Data checks of actual data compared with submitted forecast data were carried out to identify which cost drivers were eligible for the ex-post adjustment mechanism as per the incentive criteria. The submitted forecast was €177.7 million. This was updated with actual data that met the criteria for inclusion, to form the ex-post adjusted baseline of €203.1 million. This was compared with the outturn Imperfections Costs for Tariff Year 2017/18 to ascertain whether an incentive or penalty payment was due.

The outturn Imperfections Costs were €184.3 million, €18.8 million lower than the ex-post adjusted baseline. These savings are a result of the measures implemented by the TSOs during 2017/18. The results of the incentive process are set out in Figure 1.

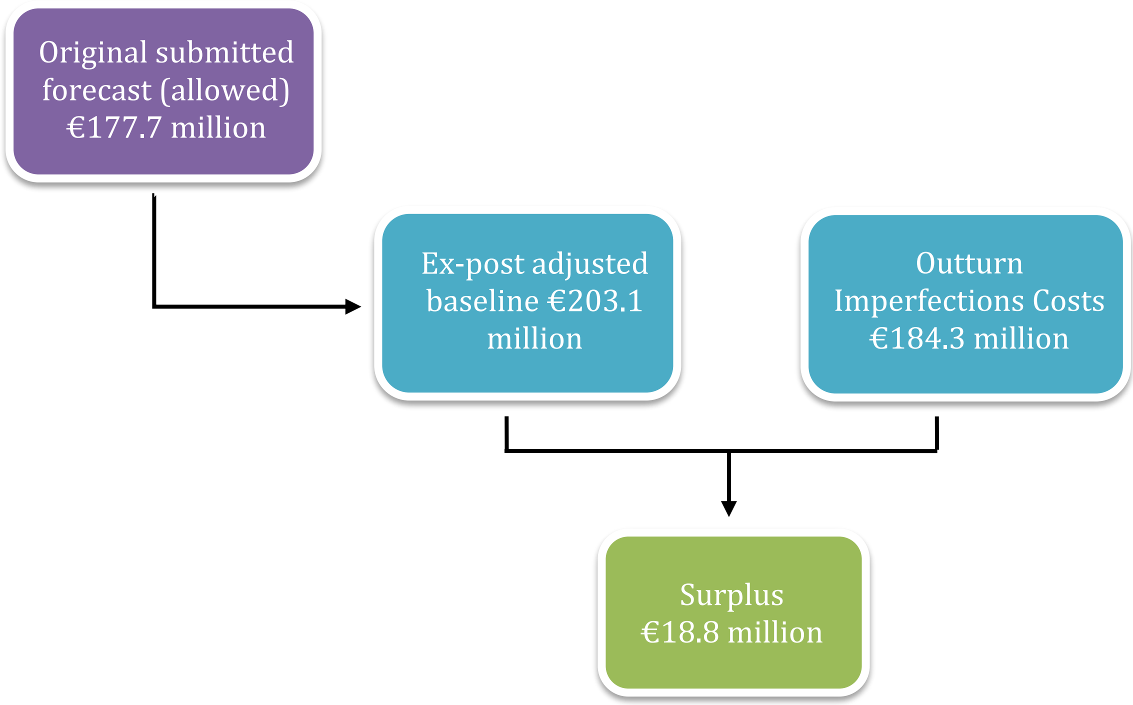

Figure 1: Flowchart of the results of the incentive process.

2. Overview of the Incentive Mechanism

To promote the effective management and reduction of outturn Imperfections Costs by the TSOs, the SEMC introduced the incentive mechanism in the 2012 decision paper SEM-12-033[1]. It outlines the agreed incentive mechanism which requires the TSOs to ex-post adjust the submitted forecast for material items that are outside of the TSOs' control. The original Imperfections revenue requirement for Tariff Year 2017/18 was €177.7 million.

To allow participants to understand the material cost drivers and the impact Imperfections Costs have on the all-island customers, the TSOs publish a Quarterly Imperfections Costs Report on their website[2].

2.1. Cost categories included in the incentive mechanism

The cost categories for the incentive mechanism, as set out in SEM-12-033, are listed below in Table 1.

Category	Included	Reason
Constraint Costs	Yes	Constraints costs are forecast by the TSOs. The constraints costs depend on a range of factors.
Uninstructed Imbalances	Yes	TSOs' influence is solely on the design of Uninstructed Imbalance (UI) tolerance parameters, such as Tolerances for Over and Under Generation, which are proposed by the TSOs.
Testing Charges	Yes	Testing charges are proposed by the TSOs and approved by the SEMC. The testing charge received into the Imperfections pot is dependent on the number of units under test and length of time a generating unit is under test.
Energy Imbalances	Yes	Link between Energy Imbalances (EI) and Constraint Costs as EI increase or decrease total Constraint Costs.
Other System Charges	Yes	Short Notice Declarations (SNDs), Trip Charges and Generator Performance Incentives (GPIs) are proposed by the TSOs. The amount of Other System Charges (OSC) received into Imperfections pot is dependent on level of non-compliances of generating units and is related to the additional costs as a result of the associated performance of generator units.
SO Trades	Yes	For system security and priority dispatch, the TSOs can countertrade utilising the Residual Capacity Unit.

[1] Decision Paper on Incentivisation SEM-12-033
[2] Quarterly Imperfections Costs Reports

Make Whole Payments	No	Independent of dispatch and DBC.
Capacity Imbalances	No	Outside control of TSOs.
Other Imperfection Charge components[3]	No	Outside control of TSOs.

Table 1: The cost categories considered for the incentive mechanism.

2.2. Components of the submitted forecast for the incentive

The following sets out the manner in which the components of Imperfections Costs, subject to the incentivisation process, are accounted for in the submitted forecast.

2.2.1. Dispatch Balancing Costs (DBC)

In the submitted forecast, DBC, the sum of Constraint Costs, Uninstructed Imbalances and Testing Tariffs, are derived from a PLEXOS model and supplementary modelling.

2.2.2. Energy Imbalance (EI)

In the submitted forecast, it is assumed that no Energy Imbalance will arise. If imbalances occur, they are assumed to have an equal and opposite effect on constraints and will offset any increase or decrease accordingly.

2.2.3. Other System Charges (OSC)

OSC are levied on generators because failure to provide necessary services to the system leads to higher DBC and Ancillary Services Costs. OSC are netted off Imperfections Costs. A zero estimate was made in the submitted forecast which assumed the generators are compliant with Grid Code and no charges are recovered through OSC. Any deviations from Grid Code compliance would result in an increase in DBC. Deviations from Grid Code non-compliance, recovered through OSC, would result in reducing the resultant costs to the system in DBC.

[3] Market Interest and Foreign Exchange elements as set out in the Trading and Settlement Code.

2.3. Ex-post review factors

The ex-post adjustment mechanism considers any factors which materially influence outturn Imperfections Costs e.g. unforeseen long-term outage of plant and other High-Impact Low-Probability (HILP) events. The factors for consideration in the ex-post review are set out in Table 2.

Factor	Level of effect on DBC	Ex-ante Baseline Adjustment
Change in SEM market rules or any RA decision affecting DBC	Automatic shift of any percentage.	SEM market rules can change during a tariff period after the ex-ante allowance has been made. These changes may have an effect on DBC outturn. If the impact of a market rule change results in any change on DBC outturn the baseline will be adjusted[4].
Changes in Demand Forecast/Exchange rates/Fuel prices (inc. bids)/Wind generation	3%+ either side of DBC baseline. Or Total 8%+ either side of DBC baseline.	Forecasts for each of these categories are included in the PLEXOS modelling of constraint costs by the TSOs. In the case of Wind forecasting a specific provision is made for the tariff period. • If the impact of the difference between forecast and actual for each category on DBC outturn is 3%+ of the baseline (in either direction), it will be adjusted[5]. • If the impact of the difference between forecast and actual of all four categories in combination on DBC outturn is 8%+ of the baseline (in either direction), it will be adjusted[6].
High Impact Low Probability (HILP) events: long-term unforeseen outage of Generators, key reserve provider or transmission plants.	5%+ of DBC baseline or €5m per event	HILPs events are rare transmission, generation or interconnector outages that lead to significant increases in constraint costs. PLEXOS does not model major HILP events. • If a Generator, key reserve provider or transmission plant going on unforeseen long-term outage (including single and multiple HILP events) results in DBC outturn increasing by 5%+ from the ex-ante baseline, it will be adjusted[7].

Table 2: The factors for consideration in the ex-post review.

[4] For example, the ex-ante baseline for Tariff Year X is €100 million. The measured impact of a market rule change is €2 million (i.e. 2% of the baseline). Therefore the baseline for Tariff Year X is adjusted by €2 million, either to €98 million or €102 million.

[5] For example, the ex-ante baseline for Tariff Year X is €100 million. The impact of the difference between forecast and actual fuel cost prices solely is €5 million (i.e. 5% of the baseline). Therefore the baseline for Tariff Year X is adjusted by €5 million, either to €95 million or €105 million. If the impact of the difference had been €2 million (i.e. 2% of the baseline), the baseline would not have been adjusted.

[6] For example, the ex-ante baseline for Tariff Year X is €100 million. The impact of the difference between forecast and actual of all four categories in combination is €12 million (i.e. 12% of the baseline). Therefore the baseline for Tariff Year X is adjusted by €12 million, either to €88 million or €112 million. If the impact had been €6 million (i.e. 6% of the baseline), the baseline would not have been adjusted.

[7] For example, the ex-ante baseline for Tariff Year X is €100 million. The impact of three Generation plants going on unforeseen long-term outage is €10 million (i.e. 10% of the baseline). Therefore the baseline for Tariff Year X is adjusted by €10 million, either to €90 million or €110 million. If the impact of the difference had been €4 million (i.e. 4% of the baseline), the baseline would not have been adjusted.

As part of the ex-post review, if there are additional significant factors to those outlined in Table 2, the combination of which leading to DBC outturn being 10% either side of the ex-ante baseline, these will be examined by the TSOs and may by be deemed eligible for an ex-post adjustment.

2.4. Asymmetric targets and dead-band

SEMC set out targets, payments and penalties for the Tariff Year 2017/18. These payments and penalties associated with the incentivisation of DBC are administered across both TSOs on a 75:25 split basis, upon ex-post review. The asymmetric targets and dead-band parameters are set out in Table 3.

€m's	Lower Bound	Dead Band	Upper Bound	Below Target	Above target
Dispatch Balancing Costs	7.5%-20% below baseline.	7.5% either side of the baseline.	7.5%-20% above baseline.	TSOs retain 10% of every 2.5% below.	TSO penalised 5% of every 2.5% above.

Table 3: The asymmetric targets and dead-band parameters.

3. Data Comparison Checks

Data checks comparing actual and forecast values were carried out to identify significant differences between the submitted forecast and reality. Data checks comprise a desktop comparison and, where required, a rerun of the DBC model in PLEXOS. When there was a material change, the submitted forecast was updated with this information.

3.1. PLEXOS model adjustments

During the ex-post review process, refinements were required to the original 2017/18 forecast PLEXOS model to ensure a more accurate and robust base case on which to measure the qualifying criteria. The refinements are as follows:

3.1.1. Initiatives introduced in 2016/17

The TSOs introduced operational initiatives during the 2016/17 tariff year which helped to reduce DBC during that year. The TSOs needed to demonstrate if fulfilling their 12 month exclusion[8] from the 1718 model would still cause a reduction in DBC. If fulfilling their 12 month exclusion does not result in a benefit to the system then the changes should be included rather than excluded in the resubmitted PLEXOS model. The analysis of initiatives introduced during 1617 is outlined as follows:

1. **SNSP 60%:** Following a successful trial from November 2016 the Non-Synchronous Generation limit permanently changed from 55% to 60% on 9th March 2017. It was found for the 2017/18 Incentive process that allowing 60% SNSP on the transmission system did not significantly decrease production costs in the model. It is therefore appropriate to include SNSP changes in the 2017/18 model.

3.1.2. New/Closing Generating Units

1. **Demand Side Units (DSUs)**
   The rate at which DSUs can become commercially operational means that there can be a significant variance from what was forecast and what actually happens. The base case model was therefore updated to include all DSUs which became operational during the 2017/18 tariff year.

2. **Solar / PV**
   The rate at which Solar/PV can become commercially operational means that there can be a significant variance from what was forecast and what actually happens. The base case model was therefore updated to include all Solar / PV which became operational during the 2017/18 tariff year.

3. **Marina Closure**
   Marina unit MRC was removed from PLEXOS from 10/09/2018.

[8] The TSOs have applied this on the basis that they are entitled to a minimum of twelve months benefit for any initiative introduced. Indeed it may be necessary to apply an initiative for a full tariff year following the tariff year in which it was introduced in order to gain the full benefit of this and for the incentive to be effective.

3.1.3. Adjustments to PLEXOS Model

1. **Increase to System Inertia Requirement**
   The system inertia requirement increased from 20,000 MWs to 23,000 MWs on 14/11/2017. This has been added to the model.

2. **SNSP 65%**
   SNSP increased to 65% from 14th November 2017 as a trial that later became permanent in March 2018. SNSP was included from 14th November 2017 in the model.

3. **Inclusion of Turlough Hill Efficiency in Ex-Post PLEXOS model**
   The Turlough Hill efficiency adjustments were included in the PLEXOS model rather than in the supplementary modelling as it was a more accurate representation of the actual efficiency of Turlough Hill. This approach was also used in the 2016/17 model.

4. **STAR Scheme**
   From June 2018, the STAR Scheme was discontinued (the scheme allowed a reduction of 54MW of static reserve). As a result, the minimum daytime operating reserve requirement in Ireland increased from 110MW to 155MW.

5. **DS3 System Services**
   From July 2018 the Minimum daytime operating reserve requirement in Ireland decreased from 155 MW to 135 MW due to DS3 System Services Contracts; similarly, the minimum daytime operating reserve requirement in Northern Ireland decreased from 50 MW to 49 MW.

6. **Reserve requirements for North-South Tie-Line Outage**
   Jurisdictional reserve in the model was adjusted to represent actual reserve during the outage, when more conventional units were run, at lower levels.

3.1.4. Gas Transportation Capacity Charges

The bidding behaviour of Ballylumford in 2017/18, based on them seeking to recover Gas Transportation Capacity charges, resulted in increased constraints costs, where they have been constrained on in dispatch to meet reserve, transmission or security constraints on the power system. Therefore the actual Ballylumford running was included in the ex-post PLEXOS model (this bidding behaviour was also present in 2016/17 and the same approach was taken).

3.1.6 UK Gas Shortage

There was a UK gas shortage that coincided with Storm Emma (end of February/start of March 2018) where the daily gas price increased to almost 5 times the normal daily price at that time of year. Daily prices for this event were included in the model.

3.2. SEM Rules or any RA decision

The TSOs reviewed any changes to SEM market rules and any RA decision that became effective between the data freeze date of 31/03/2017 and the end of the period in question. There were no changes to the SEM rules or RA rule changes which impacted on the 2017/18 process.

3.3. Demand

The actual all-island monthly demand was 0.26% lower than forecast: for Ireland it was 2.4% higher than forecast; for Northern Ireland it was 8.8% lower than forecast. The PLEXOS check of actual demand alone indicated that it did have a material impact on DBC for Tariff Year 2017/18. This resulted in a 9.97% decrease in DBC. As this was greater than the threshold of +/-3% of the baseline, this was included in the ex-post adjusted model.

3.4. Available Energy: Wind, Solar, DSU & Peat

The actual all-island wind, solar, DSU & peat availabilities were compared to the assumed availabilities in the submitted forecast. There was a relatively large decrease in available wind energy in Ireland compared to what was forecast, accounting for a large proportion of the impact.

The PLEXOS check of the combination of these availability changes indicated that it had a material impact on DBC for Tariff Year 2017/18. This resulted in a 31.25% decrease in DBC. As this was greater than the threshold of +/-3% of the baseline, this was included in the ex-post adjusted model.

3.5. Fuel Prices & Modified Interconnector Unit Nominations (MIUNs)

Actual Commercial Offer Data (COD) was compared with the submitted forecast COD and these differed enough to consider for inclusion, of note, fuel prices varied significantly from the forecast. Actual Interconnector MIUNs for 2017/18 were also updated as these differed significantly from the forecasted flows.

The impact of actual COD, including actual MIUNs, was considered material and a rerun of the PLEXOS model was carried out, to quantify this. This resulted in a 44.22% increase in DBC. As this was greater than the threshold of +/-3% of the baseline, this was included in the ex-post adjusted model.

3.6. Combination of demand, wind and Commercial Offer Data & MIUNs

When the PLEXOS model was rerun with the combination of actual demand, actual wind availability and actual COD (including MIUNs) there was an increase in DBC of 9.83%. This met the +/-8% threshold for inclusion in the ex-post adjusted model, as shown in the summary in Table 4.

Factor	Impact on DBC	Criteria for Inclusion in Ex-Post Adjusted Model	Scenario Included in Ex-Post Adjusted Model
Changes in Demand Forecast	-9.97%	± 3%	Yes
Changes in Available Energy (Wind, Solar, DSU & Peat)	-31.25%	± 3%	Yes
Changes in Exchange Rates/Fuel Prices (including MIUNs)	+44.22%	± 3%	Yes
Combined impact of changes in Demand Forecast, Exchange Rates/Fuel Prices (including MIUNs) & Wind	+9.83%	± 8%	Yes

Table 4: Summary of factors checked against the ex-post adjustment inclusion criteria.

3.7. High Impact Low Probability (HILP) events

Transmission outages, both forced and scheduled overruns, were assessed by the TSO for the Tariff Year 2017/18. Generator forced outages, scheduled outage overruns and generator issues were also examined. The combination of the generation and transmission outages met the HILP criteria as they resulted in an increase in DBC of 5.55%. This was therefore considered material and was included in the ex-post adjustment process, as shown in Table 5.

HILP	Impact on DBC	Criteria for Inclusion in Ex-post Adjusted Model	Scenario Included in Ex-post Adjusted Model
Combination of Generator Issues, Generator and Transmission Outages	+5.55%	± 5%	Yes

Table 5: Summary of HILPs checked against the ex-post adjustment inclusion criteria.

4. Ex-Post Adjustment Results

This section contains a comparison of the submitted forecast and the ex-post adjusted baseline for the Tariff Year 2017/18. A summary of the comparison is outlined in Table 6. There was a €45.88 million (€140.04 million to €185.92 million) increase in the PLEXOS component and a €25.44 million (€177.66 million to €203.10 million) increase in the total constraint costs from the submitted forecast to the ex-post adjusted baseline. The results of the ex-post adjusted PLEXOS model and the supplementary modelling are outlined in Sections 4.1 and 4.2 respectively.

Component	Submitted Forecast Forecast (€m)	Ex-Post Adjusted Baseline (€m)
PLEXOS	**140.04**	**185.92**
Supplementary Modelling	**37.62**[9]	**17.18**
Total Constraint Costs	**177.66**	**203.10**

Table 6: Summary of submitted forecast compared with the ex-post adjusted baseline.

4.1. PLEXOS results

The PLEXOS modelled component of the ex-post adjusted baseline for Tariff Year 2017/18 was found to be **€185.92 million**. This PLEXOS portion of the forecast has decreased from the submitted forecast costs of €140.04 million. The impacts of the ex-post adjusted changes on the original submitted forecast are outlined in Figure 2 below.

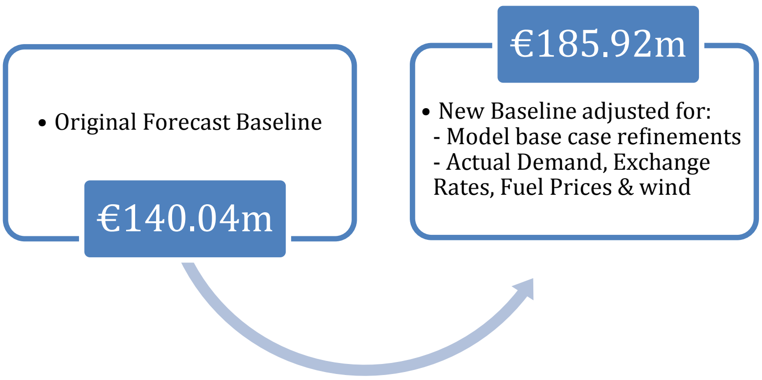

Figure 2: Ex-post adjustment process.

[9] The 2017/18 approved forecast included I-SEM components as go-live was assumed to be 23/05/2018. On the same basis, some of the SEM allowances were only forecast until 23/05/2018. As a result this is not a like for like comparison of the supplementary modelling for 2017/18. This value comprises the allowed SEM and I-SEM supplementary modelling totals (SEM allowance of €21.3m + I-SEM allowance of €16.3m).

The changes to DBC as calculated by the PLEXOS model, which resulted from both model base case refinements and actual data changes, have been outlined in Section 3.1 and summarised in Table 7.

Component	DBC (€m)
PLEXOS component of submitted forecast	**140.04**
Net of base case refinements and actual data changes adjustments	**45.88**
PLEXOS component of ex-post adjusted baseline	**185.92**

Table 7: The impact of the ex-post adjustments on the DBC baseline.

4.2. Supplementary modelling results

The supplementary modelling takes account of the specific external factors that cannot be captured by the PLEXOS model. The ex-post adjusted baseline of the constraints modelled by supplementary modelling for the Tariff Year 2017/18 was €17.18 million. This represents a significant decrease from the submitted forecast due to the forecast including €16.3m of I-SEM components that are no longer relevant. The results of the supplementary modelling process are summarised in Table 8[10].

Description		Forecast (€m)	Ex-Post Adjusted (€m)	Change (€m)
Perfect Foresight Effects	Changes to demand and generator availability	**4.54[10]**	**6.52**	**1.98**
	Wind predictability	**9.14[10]**	**13.67**	**4.53**
	Long Start-Up and Notice Times	**1.70[10]**	**0.86**	**-0.84**
Specific Reserve Constraints	Turlough Hill	**4.34**	**0.00[11]**	**-4.34**
Market Modelling Assumptions	Block Loading	**0.09**	**0.10**	**0.01**
	Hydro limitations & issues	**0.00**	**0.00**	**0.00**
System Security constraints	Capacity Testing & Performance Monitoring	**1.81**	**1.88**	**0.07**
Non-firm Wind Curtailment	Reduced cost to DBC of curtailing non-firm wind generation	**-2.46**	**-2.95**	**-0.49**
SO Interconnector Trades - Frequency Service		**0.25**	**0.00**	**-0.25**
SO Interconnector Trades - Countertrading		**6.76**	**-3.56**	**-10.32**
Secondary Fuel Start Up Testing		**0.63**	**0.66**	**0.03**
Supplementary Modelling SEM Total		**26.80[12]**	**17.18**	**-9.62**

Table 8: The results of the ex-post supplementary modelling process.

The most significant drivers of the change in forecast constraint costs in the supplementary modelling were:

1. **Wind Predictability:** More wind connected throughout the year than was forecast, combined with a higher total production cost associated with the ex-post model has increased this.
2. **Turlough Hill:** Turlough Hill efficiency is now modelled in PLEXOS.
3. **System Operator Interconnector Trades – Countertrading:** Actual trades have varied from forecast trades.

[10] At the time of calculating the 2017/18 Forecast, I-SEM go-live was assumed to be 23/05/2018. Certain I-SEM allowances are no longer relevant (I-SEM go-live delayed to 01/10/2018). To provide a relevant comparison, Table 8 shows the SEM components of the 2017/18 Forecast compared to those of the ex-post. Some components were only forecast for the SEM portion of the 2017/18 year and have been scaled to allow a comparative analysis.
[11] Turlough Hill efficiency moved from supplementary modelling to PLEXOS model, refer to Section 3.1.4.
[12] SEM Supplementary Modelling total before scaling was €21.3m.

5. Incentive Results and Conclusions

For the Tariff Year 2017/18, the ex-post adjusted baseline is €203.1 million.

Based on this ex-post adjusted baseline, the dead-band range for which no incentive payment is due is between €187.87 million and €218.33 million. If Imperfections Costs were greater than €218.33 million the penalty would be 5% of the amount above this, and if Imperfections Costs were less than €187.87 million, the incentive payment would be 10% of the amount below this, with the payments being capped at €2.54 million.

The outturn imperfections costs were €184.3 million as outlined in Table 9.

Component	Actual Outturn (€m)
Dispatch Balancing Costs	**€201.6**
SO Trades	**-€3.4**
Energy Imbalance	**-€2.5**
Other System Charges	**-€11.4**
Total Imperfections Costs	**€184.3**

Table 9: 2017/18 Outturn Imperfection Costs

The actual Imperfections cost outturn of €184.3 million is **€18.77 million** lower than the ex-post adjusted baseline. Extrapolating between 7.5% and 10% under budget equates to an incentive payment of €0.354 million, as illustrated in Table 10.

Under Budget (%)	Outturn (€)	Under Budget (€)	Incentive Payment (€)
2.5%	198,021,658	5,077,478	None
5.0%	192,944,180	10,154,957	None
7.5%	187,866,701	15,232,435	0
10.0%	182,789,223	20,309,914	507,748
12.5%	177,711,744	25,387,392	1,015,496
15.0%	172,634,266	30,464,870	1,523,244
17.5%	167,556,787	35,542,349	2,030,991
20.0%	162,479,309	40,619,827	2,538,739
22.5%	157,401,831	45,697,306	None
25.0%	152,324,352	50,774,784	None
27.5%	147,246,874	55,852,262	None

Table 10: Method of calculating the incentive payment with ex-post adjusted baseline.

The level of saving to the DBC budget represents the significant effort on behalf of the TSOs to reduce DBC where possible. A list of the primary operational initiatives introduced by the TSOs which helped to decrease DBC is as follows:

1. **<u>Dublin Generation Rules:</u>**

The following Dublin North constraint was removed from 15/05/2018:

- Requirement for 1 unit in North Dublin (for load flow and voltage control).

The following Dublin South constraint were removed from 15/05/2018:

- Requirement for 1 unit in South Dublin (for load flow and voltage control).

The following Dublin constraints were amended from 15/05/2018:

- The operation of PBA and PBB in open cycle mode can contribute towards the requirement for 2 large generators to be on load at all times in the Dublin area for voltage control'
- 'Change to number of units (increased from 1 to 2) required for load flow control in the Dublin area when Ireland System Demand is greater than 4000 MW (decreased from 4200 MW)'
- 'Change to number of units (increased from 1 to 3) required for load flow control in the Dublin area when Ireland System Demand is greater than 4700 MW (increased from 4600 MW)'

2. **<u>Kilroot Generation Rules:</u>**

The following Kilroot constraint was removed from 05/01/2018:

- There must be at least one Kilroot unit on load when the NI system demand exceeds 1400 MW and 2 units are required above 1550 MW.

In summary the TSOs have continued to introduce a significant number of operational initiatives to help reduce DBC and therefore the cost to the all-island consumer. Since the introduction of the incentive process the TSOs, through the introduction of operational initiatives, have reduced Imperfection Costs (excluding Make Whole Payments) by €117.1 million (2012/13: €3m, 2013/14: €52.4m, 2014/15: €17.2m, 2015/16: €10.5m, 2016/17: €15.3, 2017/18: €18.8m). These savings are not only realised in the year in question but are realised in following years as they become the normal operational standard.

Appendix 1: PLEXOS Modelling and 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

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 Thompson-Reuters[13] and EIA[14] reports. Carbon costs are also forecast and used, along with fuel costs, to simulate bids for generators and interconnector units in SEM and BETTA. These are then input to PLEXOS to simulate participant commercial offer data for each unit.

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

General

Feature	Forecast Assumptions	Ex-post Adjustment Assumptions
Study period	The study period is 01/10/2017 to 30/09/2018	No change
Data Freeze	The input data for the PLEXOS model was frozen on 31/03/2017	N/A
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).	No change

[13] http://eikon.thomsonreuters.com/index.html
[14] http://www.eia.gov/forecasts/steo/tables/

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.	No change
PLEXOS Version	7.3 Revision 4	No Change
Model Reference	DBC 1718 v1.0	Unconstrained: Inc1718 v1.57 Constrained: Inc1718 v1.71

Demand

Feature	Forecast Assumptions	Ex-post Adjustment Assumptions
Regional Load	NI total load and IE total load are represented using individual 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.	Actual demand in combination with other factors met the criteria for inclusion in the ex-post adjusted model.
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.	No change
Generator House Loads	These are accounted for implicitly by entering all generator data in exported terms.	No change

Generation

Feature	Forecast Assumptions	Ex-post Adjustment Assumptions
Generation Resources	Conventional generation resources are based on the All-island Generation Capacity Statement 2017-2026[15]. Historical analysis on generators' declared availability was carried out and some units seasonal ratings were adjusted based on this.	Actual wind installed capacity and availability in combination with other factors met the criteria for inclusion in the ex-post adjusted model. New Demand Side Units (DSUs) and Solar/PV units are also included.

[15] http://www.eirgridgroup.com/site-files/library/EirGrid/4289_EirGrid_GenCapStatement_v9_web.pdf

Feature	Forecast Assumptions	Ex-post Adjustment Assumptions
Production Costs	Calculated through PLEXOS using the Regulatory Authorities' publicly available dataset: 2016/17 Validated SEM Generator Data Parameters[16]. 1. Fuel cost (€/GJ) – forecasted for 2017/18 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.	Actual exchange rates, fuel prices and interconnector MIUNs were included in the ex-post adjusted model.
Generation Constraints (TOD)	Based on the data in the 2016/17 Validated SEM Generator Data Parameters[17] 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[17] was not implemented due to this decision being deferred.	No change.
Scheduled Outages	Draft outage schedules are used for 2017 and 2018 maintenance outages	Actual outage schedules are used for 2017 and 2018 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	Actual generator outages are included in the model.

[16] https://www.semcommittee.com/news-centre/baringa-sem-plexos-forecast-model-2016-17
[17] CER/14/047 – Decision on Installed Capacity Cap

Feature	Forecast Assumptions	Ex-post Adjustment Assumptions
	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.	Hydro units are modelled using daily energy.
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)[18]. 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.	Actual wind resources were included in the ex-post adjusted model.
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%.	PLEXOS model updated to reflect nominal Turlough Hill efficiency in the Unconstrained Model and actual efficiency in the Constrained Model. See Section 3.1.4 for Turlough Hill modelling.
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.	No change
Demand Side Units (DSU) and Aggregated Generator Units (AGU)	Demand Side Units and Aggregated Generator Units are modelled explicitly.	New demand side units were updated in the base case model.
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	No change

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

Feature	Forecast Assumptions	Ex-post Adjustment Assumptions
	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.	Actual MIUNs were included in the ex-post adjusted model. A variable export limit was modelled for Moyle when its exports exceeded its firm capacity of 83MW during the 1718 year.
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.	Solar/PV generation data was updated in the base case model.
Non-Synchronous Generation	System Non-Synchronous Penetration (SNSP) is set at 60% in the constrained PLEXOS model.	From 1st October 2017 – 13th November 2017 SNSP was set at 60% in the model, 65% thereafter.

Transmission

Feature	Forecast Assumptions	Ex-post Adjustment Assumptions
Transmission Data	The transmission system input to the model is based on data held by the TSOs.	No change
Transmission Constraints	The transmission system is only represented in the constrained model. The market schedule run is free of transmission constraints.	No change
Network Load Flow	A DC linear network model is implemented.	No change
Ratings	Ratings for all transmission plant are based on figures from the TSOs' database.	No change
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.	No change
Interconnection	The Moyle Interconnector and EWIC are modelled.	A variable export limit was modelled for Moyle when its exports exceeded its

Feature	Forecast Assumptions	Ex-post Adjustment Assumptions
		firm capacity of 83MW during the 1718 year.
Forced Outages	No forced outages are modelled on the transmission network.	Significant actual outages modelled.
Scheduled Outages	Major transmission outages likely to take place in the tariff year and which would impact on constraints are modelled.	Significant actual outages modelled.

Ancillary Services

Feature	Forecast Assumptions	Ex-post Adjustment 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.	In May 2018, the minimum daytime operating reserve requirement in Ireland increased from 110 MW to 155 MW due to STAR termination. In July 2018, the minimum daytime operating reserve requirement in Ireland decreased from 155 MW to 135 MW due to DS3 System Services Contracts; the minimum daytime operating reserve requirement in Northern Ireland decreased from 50 MW to 49 MW due to DS3 System Services Contracts.
Reserve characteristics	Simple straight back and flat generator characteristics are modelled. Reserve coefficients are modelled where required.	No change
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]	No change

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).	STAR scheme was discontinued from May 2018.