Imperfections Costs Incentive
For Tariff Year
1st October 2013 – 30th September 2014

2nd June 2015

Version 2.0

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 TSOs (Transmission System Operators), are responsible for managing and minimising 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 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. This submission by the TSOs represents actual outturn compared with an ex-post adjusted Imperfections revenue requirement.

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. There were three categories which were considered material, and included in the ex-post adjustment process:

- Model amendments
- Actual demand, actual exchange rates, actual Commercial Offer Data (COD) including Modified Interconnector Unit Nominations (MIUNs) and actual wind
- High Impact Low Probability events (HILPs)

The outturn Imperfections Costs incurred over the Tariff Year 2013-14 were €150.1 million; €52.4 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 without limitation to) countertrading for reserve co-optimisation and extensive focus on must-run generation constraints in Dublin.

The savings made by the TSOs during Tariff Year 2013-14 meet the requirements for receiving an incentive payment of €2.5 million.

1. Introduction

This submission to the Commission for Energy Regulation (CER) & the Utility Regulator of Northern Ireland (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 1st October 2013 to 30th September 2014 inclusive, referred to as the Tariff Year 2013-14. 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[1]. 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.

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 €165.5 million. This was updated with actual data that met the criteria for inclusion, to form the ex-post adjusted baseline of €202.5 million. This was compared with the outturn Imperfections Costs for Tariff Year 2013-14 to ascertain whether an incentive or penalty payment was due.

The outturn Imperfections Costs[2] were €150.1 million, €52.4 million lower than the ex-post adjusted baseline. These savings are a result of the measures implemented by the TSOs during the Tariff Year 2013-14. The savings made meet the requirements for receiving an incentive payment to the TSOs. The results of the incentive process are set out in Figure 1.

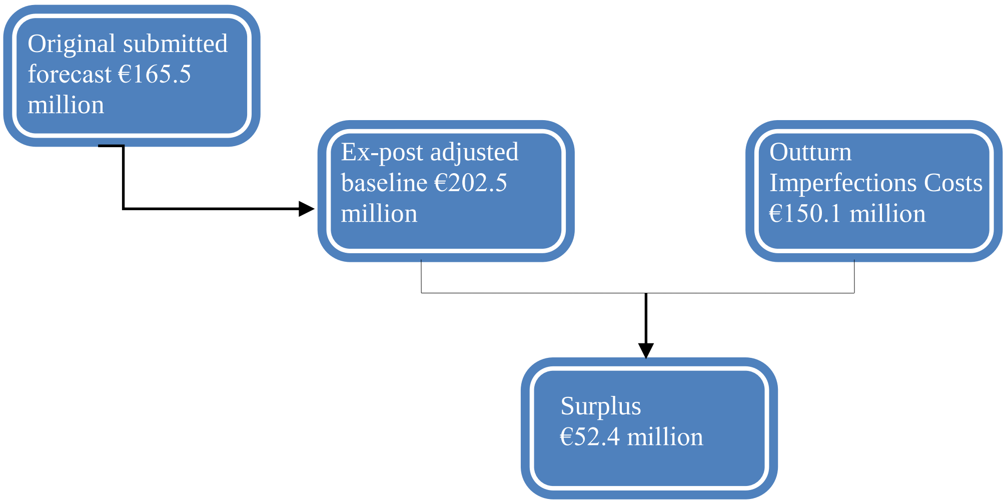

Figure 1: Flowchart of the results of the incentive process.

[1] It is noted that the SEM Committee decision has not yet been codified in the SONI licence to Participate in the Transmission of Electricity
[2] Imperfection Costs comprise of initial settlement data and does not include resettlement.

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 SEM-12-033[3] June 2012. 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 2013-14 was €165.5 million.

To allow participants to understand the material cost drivers and the impact Imperfections Costs has on the all-island customers, the TSOs publish a Quarterly Imperfections Costs Report on their website[4].

2.1. Cost categories included in the incentive mechanism

The cost categories for the incentive mechanism are set out in SEM-12-033 and are repeated 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

[3] Decision Paper on Incentivisation SEM-12-033
[4] Quarterly Imperfections Costs Reports

		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.
Make Whole Payments	No	Independent of dispatch and DBC.
Capacity Imbalances	No	Outside control of TSOs.
Other Imperfection Charge components[5]	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 whose failure to provide necessary services to the system lead 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.

[5] 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[6].
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[7]. • 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[8].
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

[6] 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.

[7] 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.

[8] 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 of had been €6 million (i.e. 6% of the baseline), the baseline would not have been adjusted.

		HILP events) results in DBC outturn increasing by 5%+ from the ex-ante baseline, it will be adjusted[9].

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

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 2013-14. 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.

[9] 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.

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 of 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 amendments

During the ex-post review process three amendments were required to the original 2013-14 forecast PLEXOS model in order to more accurately model the transmission system. Two of the model amendments related to how system constraints were set up in the model and the other related to the offtake at start for a generator, as laid out below:

- **Northern Ireland Minimum Number of Unit's Constraint**: This change was highlighted and included in the ex-post adjustment process for 2012-13, however this was almost a year after the data freeze for the forecast for 2013-14 and so was not included in the submitted forecast baseline. The constraint as modelled in the submitted forecast was considered to be unnecessarily severe, thus indicating a greater instance of out of merit running than was actually required. The constraint was amended in the ex-post adjustment process to reflect the system requirement more accurately, resulting in a reduction of €13.1 million in the ex-post baseline.

- **Dublin Transmission Constraints (three by night/two by day):** The original assumptions for the 2013-14 PLEXOS forecast model specified that in the Dublin constraint three units were required by night and two by day. This constraint was incorrectly set up in the original model. The amended arrangement of this transmission constraint in the PLEXOS model resulted in an increase to DBC of €33.5 million. This was included in the ex-post adjustment process, in order to accurately model the original assumptions.

- **Generator Offtake at Start:** The value for offtake at start for a particular CCGT was omitted from the forecast model. This value is used to calculate the start-up cost for the Generator. The inclusion of this figure decreased DBC by €1.8 million.

The combination of the above model amendments above resulted in an increase of 12.5% to the original baseline and qualified for inclusion in the ex-post adjustment process as they met the 10% threshold set in the review process. A summary is given in Table 4.

It should be noted that the above amendments were included in all subsequent data checks within PLEXOS.

Model Amendment	Impact on DBC	Criteria for Inclusion in Ex-Post Adjusted Model	Scenario Included in Ex-Post Adjusted Model
NI Min No. of Units Only	-9%	10%	No
CCGT Offtake at Start Included Only	-1%	10%	No
3 by Night/ 2 by Day (incl. CCGT as 1 unit) Only	22.5%	10%	Yes (included in combination scenario below)
Combination of All Model Amendments	12.5%	10%	Yes

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

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 29th March 2013 and the end of the period in question. There were no changes to the SEM rules but there was an RA decision that required an adjustment to the submitted forecast. The CER decision on Access Tariffs and Financing the Gas Transmission System[10] resulted in nine gas generators in Ireland increasing their offer prices to include the Gas Transportation Capacity (GTC) charge. The effect of this was a significant increase in DBC between October 2013 and April 2014. For example, the average increase in offer prices for these nine units between October 2013 and December 2013 was over 20% and between January 2014 and March 2014 was over 40%. PLEXOS calculated that the impact of the inclusion of the GTC charge on DBC was approximately €30 million. The GTC for the nine Ireland gas units was included in the actual Commercial Offer Data (COD) and was applied to the ex-post adjusted model.

3.3. Demand

The actual average monthly demand for Ireland was found to be 0.5% lower than forecast while that of Northern Ireland was 1.7% lower than forecast. The PLEXOS check of actual demand alone also indicated that it did not have a material impact on DBC for Tariff Year 2013-14. The impact on DBC in the PLEXOS rerun was found to be <1%. This meant that demand alone did not meet the criteria for inclusion in the ex-post adjusted model.

3.4. Wind

Actual all-island wind availability was 7% lower than the assumed wind availability in the submitted forecast. This was considered a material difference and a rerun of the PLEXOS model was carried out. This model rerun showed a reduction in DBC of 1% when compared with the submitted forecast. A change in actual wind availability alone was therefore not included in the ex-post adjusted model.

3.5. Commercial Offer Data & Modified Interconnector Unit Nominations

Actual COD was compared with the submitted forecast COD. Generator offers differed significantly throughout the tariff year for a number of reasons. During the first half of the year the inclusion of the GTC charge in the offers of nine of the Ireland gas Generators increased DBC as outlined in Section 3.2. The trend in DBC outturn tracked the GTC

[10] CER/13/191; Access Tariffs and Financing the Gas Transmission System; 21st August 2013

charge, which peaked in February 2014 and then reduced to almost zero in May 2014. DBC in the second half of the year was heavily influenced by the reduction of wholesale gas prices. For example between April 2014 and June 2014 actual wholesale gas prices were 5% lower than forecast, which had the effect of reducing DBC.

Forecasted Modified Interconnector Unit Nominations (MIUNs) on both Interconnectors were based on the high imports that had been seen historically prior to the data freeze. However, actual MIUNs for the Tariff Year 2013-14 differed somewhat. While they were predominantly still imports, there was a greater volume exported than had been forecast. EWIC has the potential to be the Largest Single Infeed (LSI) on the island when importing at high levels. The point at which EWIC becomes the LSI and therefore cannot provide reserve changed from that forecast when the actual MIUNs were analysed. This was due to actual imported values being lower than forecast. Therefore when updating the actual MIUNs the EWIC LSI trigger point also had to be updated. The actual metered generation of seven other units that had the potential to be the LSI were compared to the actual EWIC MIUNS for each interval throughout the tariff year to ascertain the average import value of EWIC when it became the LSI. This was found to be lower than the value forecast, which meant that reserve was required from other units at an earlier stage than initially assumed. This resulted in more units being constrained on in the constrained model, thereby increasing DBC.

The actual COD (including actual MIUNs) was considered material and a rerun of the PLEXOS model was carried out. This resulted in a €20.7 million increase to DBC. This was the net effect of the GTC (increased DBC), low gas prices in the summer (decreased DBC) and actual MIUNs (increased DBC). As this was greater than the threshold of 3% of the baseline, this update warranted inclusion 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 €31.6m from the baseline (that included model amendments). This equated to an 18.8% increase in DBC and met the 8% threshold for inclusion in the ex-post adjusted model, as shown in the summary in Table 5 below.

Factor	Impact on DBC	Criteria for Inclusion in Ex-Post Adjusted Model	Scenario Included in Ex-Post Adjusted Model
Changes in Demand Forecast	0.6%	3%	No
Changes in Wind	-1%	3%	No

Changes in Exchange rates/Fuel prices (including MIUNs, EWIC LSI trigger point and GTC charges)	12.3%	3%	Yes (included in combination scenario below)
Changes in Demand Forecast, Exchange rates/Fuel prices (including MIUNs, EWIC LSI trigger point and GTC charges) and Wind	18.8%	8%	Yes

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

3.7. High Impact Low Probability (HILP) events

Transmission outages, both forced outages and scheduled outage overruns, were assessed by the TSO for the Tariff Year 2013-14. There were seven transmission HILP events which were deemed likely to impact DBC and required a rerun of the PLEXOS model.

- 400 kV transmission outage
- Dublin-Cork transmission outages
- North-South tie-line outage
- Transmission line outages in the North-West region
- Raffeen Coupler outage
- Derated lines
- A specific CCGT outage combined with specific transmission outages (Arklow T2102 Transformer, Great Island T2101 Transformer, Kilbarry-Knockraha TWO 110 kV Line, Kilbarry-Mallow 110 kV Line, Great Island-Kellis 220 kV line, Corduff-Finglas & Maynooth - Woodland 220 kV lines)

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 reduced DBC by 7% or €13.6 million. The main reason why these HILPs reduced DBC is as follows:

- The generator forced outages were on units which would be expected to be in merit in the Single Electricity Market (SEM). This then resulted in more expensive generation being in merit in SEM than would otherwise be the case. Some of these expensive generators are required to be constrained on by the TSOs due to security reasons, therefore many of these generator forced outages helped to reduce the impact of otherwise constraining these units on.
- A generator which was must-run due to system security reasons experienced a technical issue with the plant which resulted in its minimum generation level being significantly higher than normal and that required under the Grid Code. The result of this was that the unconstrained model did not dispatch this on as much as in the submitted forecast model, however the TSOs required this to be must-run at times during the Tariff Year 2013-14, therefore the overall impact was that this reduced the original DBC baseline.

This was therefore considered material and included in the ex-post adjustment process, as shown in Table 6 below.

HILP	Impact on DBC	Criteria for Inclusion in Ex-post Adjusted Model	Scenario Included in Ex-post Adjusted Model
Combination of Generator Outages, Generator Issue and Transmission Outages	-7%	5%	Yes

Table 6: 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 2013-14. A summary of the comparison is outlined in Table 7. There was a **€36.6 million** increase in the PLEXOS component 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 (€m)	*Ex-Post* Adjusted Baseline (€m)
PLEXOS	**€149.2**	**€185.8**
Supplementary Modelling	**€16.3**	**€16.7**
Total Constraint Costs	**€165.5**	**€202.5**

Table 7: 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 2013-14 was found to be **€185.8 million**. This PLEXOS portion of the forecast has increased from the submitted forecast costs of €149.2 million. The impacts of the ex-post adjusted changes on the original submitted forecast are outlined in Figure 2 below.

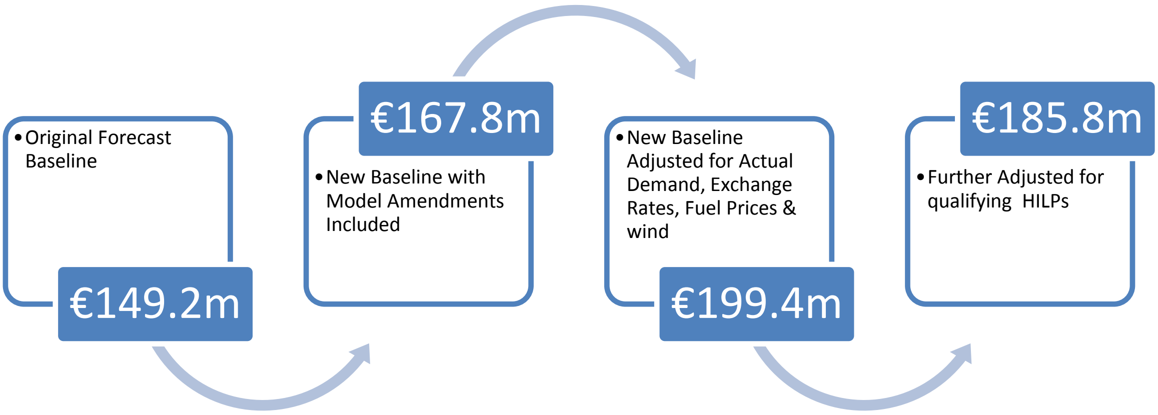

Figure 2: Flowchart of the sequence of calculations made in the ex-post adjustment process.

The changes to DBC as calculated by the PLEXOS model resulted from both model amendments and actual data changes (including HILPs) and are outlined below in Table 8.

<u>Model amendments:</u>

- The combination of the model amendments, outlined in Section 3.1, included in the ex-post adjusted model resulted in a change of 12.5% to the original baseline and qualified for inclusion in the ex-post adjusted model as they met the 10% threshold set in the review process.

<u>Actual data changes:</u>

- Combination of actual demand, wind, COD (including MIUNs) met the criteria of 8% for inclusion in the ex-post adjusted baseline.
- HILPs: The combined impact of generation and transmission HILPs were included in the ex-post adjusted baseline, as they were over the 5% threshold.

Component	DBC (€m)
PLEXOS component of submitted forecast	€149.2
Model amendments	€18.6
Combination of actual demand, wind, COD (including MIUNs, GTC)	€31.6
HILPs	-€13.6
Ex-post adjusted DBC PLEXOS Total	€185.8

Table 8: 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 2013-14 was €16.7 million. This represents an increase of €0.4 million from the submitted forecast. The results of the supplementary modelling process are summarised in Table 9.

Description		Forecast 2013-14 (€m)	Ex-Post Adjusted 2013-14 (€m)	Change (€m)
Perfect Foresight Effects	Changes to demand and generator availability	7.2	6.5	*-0.7*
	Wind predictability	9.2	8.3	*-0.9*
	Long Start-Up and Notice Times	2.8	3.5	*+0.7*
	Interconnector schedule set D-1	0.0	0.0	*0.0*
Specific Reserve Constraints	Turlough Hill	4.7	4.3	*-0.4*
Market Modelling Assumptions	Block Loading	0.7	0.7	*0.0*
	Hydro limitations & issues	0.0	0.0	*0.0*
System Security constraints	Capacity Testing & Performance Monitoring	1.4	2.1	*+0.7*

Non-firm Wind Curtailment	**Reduced cost to DBC of curtailing non-firm wind generation**	**-1.7**	**-0.7**	***+1.0***
System Operator Interconnector Trades - Countertrading		**-8.0**	**-8.0**	***0.0***
Supplementary Modelling Total		**16.3**	**16.7**	***0.4***

Table 9: 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:

- **Lower Perfect Foresight Effects:** Lower average System Marginal Price (SMP) in the unconstrained model resulted in a reduction in the cost of some of the Perfect Foresight provisions.
- **Long Start-Up and Notice Times:** An increase in elements of COD for the Unit tested resulted in a slight increase to this provision.
- **Specific Reserve Constraints:** This provision takes account of the reduced efficiency of operation of Turlough Hill in certain modes which cannot be modelled in PLEXOS. This efficiency reduction effectively reduces the total energy available in the actual dispatch. This energy must be replaced (by the marginal plant), resulting in additional constraint costs over the day. A decrease in the average daytime SMP resulted in a reduction in this provision.
- **Capacity Testing and Performance Monitoring:** There was an overall increase of €700k in this provision due to an increase in the net costs per test for the units that were tested combined with an increase in the number of tests required, as some of the units weren't dispatched to the same extent in the ex-post model as they were in the forecast model.
- **Wind with non-firm access:** This provision reduces the forecast constraint costs in the supplementary modelling. This reduction offsets the forecast constraint costs over-estimated by the PLEXOS model, which does not differentiate between wind generation units with firm and non-firm access when wind is dispatched down. This provision reduced by €1m due to lower curtailment and a lower average night time SMP in the ex-post adjusted model.

The provisions that were reviewed but not included in the *ex-post* adjustment as they didn't meet the criteria of the incentive process were:

- **System Operator Interconnector Trades:** The original provision for SO interconnector countertrading was €8 million. The actual figure for Priority dispatch countertrading only was approximately €9.5 million. This only represents a 1% change from the forecast baseline and so was not included in the ex-post adjusted baseline.

5. Incentive Results and Conclusions

For the Tariff Year 2013-14, the ex-post adjusted baseline was €202.5 million. Based on this ex-post adjusted baseline, the dead-band range was between €187.3 million and €217.7 million. If Imperfections Costs were greater than €217.7 million the penalty would be 5% for every 2.5% of the deficit and if Imperfections Costs were less than €187.3 million, the incentive payment would be 10% for every 2.5% of the surplus. The outturn imperfections costs were €150.1 million, which was **€52.4million** lower than the ex-post adjusted baseline. This equates to an incentive payment of €2.5 million, as illustrated in Table 10 below.

Under Budget (%)	Outturn (€)	Under Budget (€)	Incentive Payment (€)
2.5%	197,437,500	5,062,500	Deadband
5.0%	192,375,000	10,125,000	Deadband
7.5%	187,312,500	15,187,500	0
10.0%	182,250,000	20,250,000	506,250
12.5%	177,187,500	25,312,500	1,012,500
15.0%	172,125,000	30,375,000	1,518,750
17.5%	167,062,500	35,437,500	2,025,000
20.0%	162,000,000	40,500,000	2,531,250
22.5%	156,937,500	45,562,500	Deadband
25.0%	151,875,000	50,625,000	Deadband
27.5%	146,812,500	55,687,500	Deadband

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. The main savings were generated by the introduction of countertrading on EWIC for reserve co-optimisation and changing the number of units in the Dublin operational constraint.

Countertrading for reserve co-optimisation was introduced by the TSOs in early March 2014 following consultation with the RAs. The principle behind this initiative was that the TSOs would countertrade with Great Britain (GB) to export across EWIC in order to prevent it from becoming the LSI. By doing this it meant that EWIC could still hold reserve and the amount of reserve required on the island was minimised. It has a two-fold benefit on DBC. Firstly, there was a production cost saving associated with it and secondly revenue generated from the exported flows with GB was netted off DBC.

The number of units in the Dublin operational constraint for voltage support was reduced from three by night/two by day to two (plus EWIC) at all times, following a period of successful testing. This new operational constraint was not in place for the entire Tariff Year 2013-14 but when it was in place it helped to reduce DBC. The reduction was down to a decrease in dispatch production costs as fewer units were required to run in Dublin.

These TSO initiatives were the driving factors behind the savings of €52.4 million generated during Tariff Year 2013-14, against the ex-post adjusted baseline of €202.5 million. The difference between outturn imperfections costs and the ex-post adjusted baseline are outlined in Table 11.

Component	2013-14 Actual Outturn (€m)	*Ex-post* Adjusted baseline (€m)	Difference (€m)
Dispatch Balancing Costs	**€157.4**	**€202.5**	**-€45.1**
Energy Imbalance	**-€0.7**	**€0**	**-€0.7**
Other System Charges	**-€6.6**	**€0**	**-€6.6**
Imperfections Costs	**€150.1**	**€202.5**	**€52.4**

Table 11: The difference between outturn Imperfections Costs and the ex-post adjusted baseline.

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 2013/14 are defined in €/GJ based on the long term fuel forecasts from Thompson-Reuters[11] and HEREN[12] reports and information available from the ICE futures website[13]. 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.

It was announced in the HM Treasury Budget 2013 that Northern Ireland would be exempt from the Carbon Price Floor from 1st April 2013[14,15]. This has been taken into account for generator units in Northern Ireland.

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 1st October 2013 to 30th September 2014.	N/A
Data Freeze	The input data for the PLEXOS model was frozen on 29th March 2013.	N/A

[11] http://thomsonreuters.com/products_services/financial/financial_products/commodities/energy/
[12] http://www.icis.com/heren/
[13] https://www.theice.com/homepage.jhtml
[14] http://www.hm-treasury.gov.uk/budget2013_policy_decisions.htm#Carbon_price_floor_Northern_Ireland_exemption
[15] http://www.hmrc.gov.uk/budget2013/tiin-1006.pdf

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
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	6.208 R04	6.208 R04
Model Reference	Unconstrained: DBC 1314 UC v3.4 Constrained: DBC 1314 v1.6	Unconstrained: DBC 1314 UC v4.0 Constrained: DBC1314 C v2.0

Demand

Feature	Forecast Assumptions	Ex-post Adjustment Assumptions
Regional Load	NI total load and IE non-industrial 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. The IE profile is net of industrial load.	Actual demand in combination with other factors met the criteria for inclusion in the ex-post adjusted model.
Non Industrial 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
Industrial Demand Data (Ireland)	Industrial loads are generally constant over the day, though some loads change between day and night hours. Rather than following the system demand profile, they are modelled explicitly as purchasers in PLEXOS with a constant load.	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 2013-2022. Historical analysis on generators declared availability was carried out and some units seasonal ratings were adjusted based on this.	Actual wind availability in combination with other factors met the criteria for inclusion in the ex-post adjusted model.
Production Costs	Calculated through Plexos using the Regulatory Authorities' publicly available dataset: 2012-13 Validated SEM Generator Data Parameters - Public. Certain changes have been made to this dataset where necessary. • Fuel cost (€/GJ) – forecasted for 2013 and 2014 from Thomson Reuters • Piecewise linear heat rates (GJ/MWh) • No Load rate (GJ/h) • Start energies (GJ) • Variable Operation & Maintenance Costs (€/MWh) It was announced in the HM Treasury Budget 2013 that Northern Ireland would be exempt from the Carbon Price Floor from 1st April 2013[16,17]. 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, MIUNs and GTC charge were included in the ex-post adjusted model.
Generation Constraints (TOD)	Based on the data in the 2012-13 Validated SEM Generator Data Parameters, the following technical characteristics are implemented: • Maximum Capacity • Minimum Stable Generation • Minimum up/down times • Ramp up/down limits • Cooling Boundary Times Changes to these parameters have been made where necessary to reflect approved Technical Offer Data (TOD) in the SEM market systems.	Operational issues at a specific CCGT resulted in a higher minimum generation from 25/11/2013 to 26/03/2014, which was included as a HILP in the ex-post adjusted model.
Scheduled Outages	Draft outage schedules are used for 2013 and 2014 maintenance outages.	No change
Forced Outages	Forced outages of generators are determined using a method known as Convergent Monte Carlo. Forced Outage Rates and Mean Times to Repair are based on EirGrid/SONI forecasts and historical data.	Actual forced outages, scheduled outage overruns and Forced Outage Rates were included as HILPs in

[16] http://www.hm-treasury.gov.uk/budget2013_policy_decisions.htm#Carbon_price_floor_Northern_Ireland_exemption
[17] http://www.hmrc.gov.uk/budget2013/tiin-1006.pdf

Feature	Forecast Assumptions	Ex-post Adjustment Assumptions
		the ex-post adjusted model.
Hydro Generation	Hydro units are modelled using daily energy limits. Other hydro constraints (such as drawdown restrictions and reservoir coupling) are not modelled.	No change
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 (Q3 2012)[18].	Actual wind availability was included ex-post adjusted model.
Turlough Hill	Modelled as 4 units of 73 MW. The usable reservoir volume is 1,590MWh. The efficiency of the unit is 70%. It is assumed that the units are all operational by start of study period.	No change
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.	NI minimum number of units constraint and the Dublin 3 units by night / 2 by day were corrected in the ex-post adjusted model.
Demand Side Units (DSU) and Aggregated Generator Units (AGU)	Demand Side Units and Aggregated Generator Units are modelled explicitly.	No change
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	No change
Interconnector Flows	Interconnector flows with Great Britain (GB) are forecast to be predominantly imports into SEM. This reflects historical experience of flows on both interconnectors prior to the Data Freeze and is a best estimate of likely future flows.	Actual MIUNs and a revised trigger point where EWIC cannot provide reserve were included in the ex-post adjusted model.

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	No change

[18] http://www.eirgrid.com/media/All%20Island%20Renewable%20Connection%20Report%20-%2036%20Month%20Forecast%20(Q3%202012).pdf

Feature	Forecast Assumptions	Ex-post Adjustment Assumptions
	schedule run is free of Transmission constraints.	
Network Load Flow	A DC linear network model is implemented.	No change
Ratings	Ratings for all transmission plant are based on figures from the Planet database and those provided by SONI. Comparisons have been made against the Protection network database and changes have been made where appropriate.	No change
Tie-Line	The North-South tie-line is not represented in the unconstrained model. The Net Transfer Capacity (NTC) is modelled in the constrained schedule, with flow limits set to 300MW N-S and 200MW S-N.	No change
Interconnection	The Moyle Interconnector and EWIC are modelled.	No change
Forced Outages	No forced outages are modelled on the transmission network.	7 Transmission outage HILP events were included in the ex-post adjusted model.
Scheduled Outages	Major transmission outages are modelled.	No change

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.	No change
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[19].	No change

[19] http://www.eirgrid.com/media/Operational%20Constraints%20Update%20Version%201%205.pdf

Static sources	Static reserve provided by STAR (an interruptible load scheme) is modelled. It is assumed that 35MW of static reserve is available from 07:00 to 00:00.Static reserve will be available on Moyle if there is sufficient unused capacity available, up to a maximum of 75 MW. Static reserve will be available on EWIC if there is sufficient unused capacity available, up to a maximum of 50 MW. An overall maximum limit of 100MW of static reserve from Interconnection is modelled.	No change

