Information note on 2012 Distribution System Operator allowed revenue, DUoS tariffs & DLAFs

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Abstract:

This information note outlines the approved:

- Distribution System Operator (DSO) allowed revenue for the 2012 calendar year;
- Distribution Use of System (DUoS) tariffs for the 12 month period from 1 October 2011 to 30 September 2012; and,
- Distribution Loss Adjustment Factors (DLAFs) for the 12 month period from 1 October 2011 to 30 September 2012.

Target Audience:

This information note is for the attention of members of the public, the energy industry, customers and all interested parties.

It will be of particular interest to parties who pay Distribution Use of System charges and end-user customers to whom these charges are passed on.

Related Documents:

CER10198 Decision on DSO revenue for 2011 to 2015

Executive Summary

This information note outlines the approved:

- Distribution System Operator (DSO) allowed revenue for the 2012 calendar year;
- Distribution Use of System (DUoS) tariffs for the 12 month period from 1 October 2011 to 30 September 2012; and,
- Distribution Loss Adjustment Factors (DLAFs) for the 12 month period from 1 October 2011 to 30 September 2012.

The approved DUoS tariffs and DLAFs are published alongside this paper.

<u>DSO allowed revenue</u>

In 2010 the CER published its decision on the revenue that the DSO could collect from its customers through DUoS tariffs over the 2011 to 2015 period.

As provided for within that decision, this information note provides an update on the DSO revenue relating to the 2012 calendar year. This figure feeds into the DUoS tariffs that are approved for implementation over the 1 October 2011 to 30 September 2012 period.

The DSO revenue for the 2012 calendar year is €721.6m, which compares to €675.7m for the 2011 calendar year.

The Average Unit Price for Distribution Use of System charges for the 1 October 2011 to 30 September 2012 period is 3.05c/kWh. This is a 5.3% increase relative to the AUP of 2.90c/kWh for the 1 October 2010 to 30 September 2011 period.

The major updates covered in this note relate to revised assumptions or outturn values for new connections, gigawatthours consumed and indexation. Updates are also included for other more specific items such as prepaid meters.

Four documents have been published alongside this decision paper. These are:

- The approved DSO schedule of DUoS tariffs which will apply during the 1 October 2011 to 30 September 2012 period;
- The excel model that was used to update the 2012 DSO revenue;
- An explanatory note from the DSO explaining the updates to the model; and,
- The approved DLAFs which will apply during the 1 October 2011 to 30 September 2012 period.

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1.0 Introduction

1.1 The Commission for Energy Regulation

The Commission for Energy Regulation ('the CER') is the independent body responsible for overseeing the regulation of Ireland's electricity and gas sector's. The CER was initially established and granted regulatory powers over the electricity market under the Electricity Regulation Act, 1999. The enactment of the Gas (Interim) (Regulation) Act, 2002 expanded the CER's jurisdiction to include regulation of the natural gas market, while the Energy (Miscellaneous Provisions) Act 2006 granted the CER additional powers in relation to gas and electricity safety. The Electricity Regulation Amendment (SEM) Act 2007 outlined the CER's functions in relation to the Single Electricity Market (SEM) for the island of Ireland. This market is regulated by the CER and the Northern Ireland Authority for Utility Regulation (NIAUR). The CER is working to ensure that consumers benefit from regulation and the introduction of competition in the energy sector.

1.2 Purpose of this paper

This paper provides information on:

- The approved Distribution System Operator (DSO) revenue for the 2012 calendar year;
- The approved Distribution Use of System (DUoS) tariffs to apply from 1 October 2011 to 30 September 2012; and,
- The approved Distribution Loss Adjustment Factors (DLAFs) to apply from 1 October 2011 to 30 September 2012.

1.3 Structure of this paper

This paper is structured in the following manner:

Section 1 provides an introduction to and outlines the purpose of this information note.

Section 2 provides background information. It outlines how the decisions made when setting the DSO revenue for the 2011 to 2015 period[1] are being implemented to set the DSO revenue for the 2012 calendar year. It also outlines how DUoS tariffs are set to recover that revenue. Section 2 also provides information on how DLAFs are set each year.

Section 3 provides detail on the DSO revenue that has been approved for the 2012 calendar year.

Section 4 provides detail on the DUoS tariffs that are approved for implementation from 1 October 2011 to 30 September 2012.

[1] The decision on DSO revenue for the 2011 to 2015 period is available here.

Section 5 provides detail on the DLAFs that are approved for implementation from 1 October 2011 to 30 September 2012.

Section 6 provides a summary.

Four documents are published alongside this paper. These are:

- The approved DSO schedule of DUoS tariffs which will apply during the 1 October 2011 to 30 September 2012 period;
- The excel model that was used to update the 2012 DSO revenue;
- An explanatory note from the DSO explaining the updates to the model; and,
- The approved DLAFs which will apply during the 1 October 2011 to 30 September 2012 period.

2.0 Background Information

2.1 DSO revenue control for the period 2011 to 2015

In November 2010, the CER published a decision paper detailing the level of DSO revenue for the period 2011 to 2015 (CER/10/198[2]). The allowed revenue set for each calendar year of the period is shown in the below table in 2009 terms.

(2009 monies, €m)	**2011**	**2012**	**2013**	**2014**	**2015**
DSO Allowed Revenue	682.6	717.4	754.7	797.3	842.9

Table 1: DSO allowed revenues 2011-2015

2.2 Yearly updates of calendar year revenue

The decision paper on DSO revenue for the 2011 to 2015 period provided for the revenue for each calendar year being updated during the period (for example, to reflect changes in GWh assumptions). The decision stated that during the control period the CER would publish information notes outlining the effect of implementing the yearly updates. This replaces the consultation process that was completed for 2010 and previous years.

An excel model was subsequently developed by the CER to facilitate these updates. The model is to be completed year in advance by the DSO (for example, the 2012 calendar year revenue is to be updated in 2011), and submitted to the CER for review and approval.

This process has been completed for the 2012 calendar year. An updated model has been provided by the DSO and reviewed by the CER. The CER is satisfied that the model correctly implements the decision paper. Details on the updated approved revenue for 2012 are provided within Section 3 of this paper.

2.3 Determination of DUoS tariffs for each tariff period

In recent years, the CER has approved DUoS tariffs on an annual basis to cover the period from 1 October to 30 September. Essentially, DUoS tariffs are set to recover 26.7%[3] of the calendar year revenue for year one and 73.3%[3] of the calendar year revenue for year two (covering the revenue relating to October to December and January to September, respectively.

Details on the approved DUoS tariffs for the 1 October 2011 to 30 September 2012 period are provided within Section 4 of this paper.

[2] The decision on DSO revenue for the 2011 to 2015 period is available here.

[3] This is based on the percentage of demand that relates to the relevant period of the year.

2.4 Determination of DLAFs

Details on the DLAFs for the 1 October 2011 to 30 September 2012 period are provided within Section 5 of this paper. Information on the methodology which the DSO uses to determine these values is available on the CER website[4].

[4] The methodology used by the DSO to determine DLAFs is available here.

3.0 DSO revenue for the 2012 calendar year

3.1 Introduction

As detailed in Section 2.1, in November 2010 the CER published a decision paper detailing the level of DSO allowed revenue for the period 2011 to 2015[2]. That decision paper also detailed how the allowed revenue would be updated each year.

The DSO revenue for the 2012 calendar year has been updated according to the above decision paper and consequently the CER approves DSO revenue of €721.6m for the 2012 calendar year. This section of this information note provides details on the revenue submission provided by the DSO and the calculations that led to this figure.

Parties that require further information should refer to the excel model (developed by the CER and completed by the DSO) and a DSO explanatory document, both of which are published alongside this information note.

3.2 DSO revenue for the 2012 calendar year

3.2.1 Revenue control formula

The revenue control formula, which is used to keep the DSO's revenue in line with allowed costs, is set out in detail in Section 11 of CER/10/198[2]. Very simply, the revenue control formula takes the 'base' allowed revenue (in 2009 monies, as detailed in Table 1), inflates that revenue into nominal figures, and adjusts it for specific revenue parameters. The following formula is used:

$$R_t = \prod_{2010}^{t}[(1+INF_j)/100]*B_t + \prod_{2010}^{t}[(1+INF_j)/100*[\Delta INCENT_t + PCust_t*(FCust_t - Cust)_t]$$
$$+\Delta P_t + \Delta U_t + K_{t-1} + K_{t-2}$$

Equation 1: Price control formula from CER/05/138

The terms within this equation are defined fully within CER/10/198. For the 2012 calendar year:

- R_{2012}, the maximum level of revenue allowed in 2012, is €721.6 m;
- When adjusting from 2009 to 2012 values, the relevant figures are multiplied by 1.009[5];
- B_{2012}, the level of allowed revenue for the 2012 calendar year in real 2009 prices as detailed in CER/10/198, is €717.4m[2];
- $\triangle INCENT_{2012}$, the difference in value of incentives/penalties earned in 2012 from an assumed incentive payment of €8m (in real 2009 prices) in 2012, is zero[6];

[5] HICP of -1.6%, +1.5% and 1.0% for each of the years from 2010 to 2012.

[6] Note that this is set at zero for 2012 as no outturn data is yet available for 2012 to estimate the magnitude of those payments/penalties.

- $PCust_{2012}$, the revenue earned or foregone by the DSO for each additional connection above or below forecasted levels, is €0.00010246m;
- $FCust_{2012}$, the current forecast for new connections for the period 2011 to 2012, is 46,951[7];
- $Cust_{2012}$, the number of new connections assumed for the period 2011 to 2012 in the determination of B_{2012}, is 57,709[7];
- $\triangle P_{2012}$, the change in 2012 pass-through costs from those assumed in the determination of B_{2012}, is 0.0m[8];
- $\triangle U_{2012}$, the change in 2012 uncertain costs from those assumed in the determination of B_{2012}, is -€1.6m;
- K_{t-1}, the correction factor for 2011, is €25.3m;
- K_{t-2}, the correction factor for 2010, is -€25.8m;

These figures are explained in more detail in the following section and are broken down further within Table 2.

3.2.2 Explanation of k factors and adjustments to 2012 revenue

The above shows that B_{2012} for 2012 was adjusted for inflation to give a figure of €723.7m. This figure was then adjusted downwards to yield the total value of €721.6m for DSO revenue for the 2012 calendar year. Table 2 shows that of this reduction:

- -€1.6m relates directly to 2012 and is included within Equation 1 under the terms '$PCust_t$/$FCust_t$/$Cust_t$' and $\triangle U_t$;
- €25.3m related to the k_{t-1} factor for 2011; and,
- -€25.8m related to the k_{t-2} factor for 2010.

[7] The definitions of $PCust_t$ and $FCust_t$ within the PR3 decision referred to '....new connections .... in year t...'. This is corrected here so that the definitions refer to new connections from 2011 to year t (inclusive).

[8] This value is zero for 2012. Changes in pass-through costs for 2010 are fed through this equation through the k_{t-2} value.

	2010	2011	2012	Total
Insurance, rates, ESI levy	(3.49)	0.00	0.00	(3.49)
Total Pass-through Costs	**(3.49)**	**0.00**	**0.00**	**(3.49)**
Higher (lower) customer numbers	(0.66)	(0.94)	(1.10)	(2.71)
Higher (lower) non-repayable line diversion costs	(2.15)	0.00	0.00	(2.15)
Pension deficit	0.43	(4.27)	0.00	(3.84)
RMDS – industry co-ordination & design	(0.07)	0.80	0.00	0.73
Keypad & token meters	0.00	7.8	0.00	7.8
Electric Ireland smart metering pilot costs	0.00	3.2	0.00	3.2
Load research	0.00	0.00	0.15	0.15
Moves to dual meters	2.08	0.00	0.00	2.08
Adjustments re 2010 capex	(1.83)	(3.04)	(2.18)	(7.05)
Change to PR1 contributions methodology	0.83	1.75	1.74	4.32
Generator connections	(0.09)	(0.19)	(0.19)	(0.47)
Total Uncertain Costs	**(8.44)**	**5.11**	**(1.59)**	**(4.92)**
Actual indexation different to forecast	(8.50)	6.03	0.00	(2.47)
Actual revenue lower(higher) than forecast	(30.82)	14.70	0.00	(16.12)
Total Indexation/revenue	**(39.32)**	**20.73**	**0.00**	**(18.59)**
Customer minutes lost	10.19	0	0	10.19
Customer interruptions	5.66	0	0	5.66
Customer satisfaction rating	1.70	0	0	1.70
Total incentives	**17.55**	**0**	**0**	**17.55**
Total (pre-interest)	(26.71)	25.86	(1.59)	(2.47)
Total adjustments	**(25.79)**	**25.34**	**(1.59)**	**(2.04)**

Table 2: *k factors and adjustments to revenue for 2012*

The below graph shows the impact that the factors documented within Table 2 have on the base revenue that was allowed for 2012 as part of the five-year revenue control. Explanations of the figures are provided in the following section according to the order in which they appear in Table 2. Please note that an excel spreadsheet detailing the calculations behind these figures is published alongside this note.

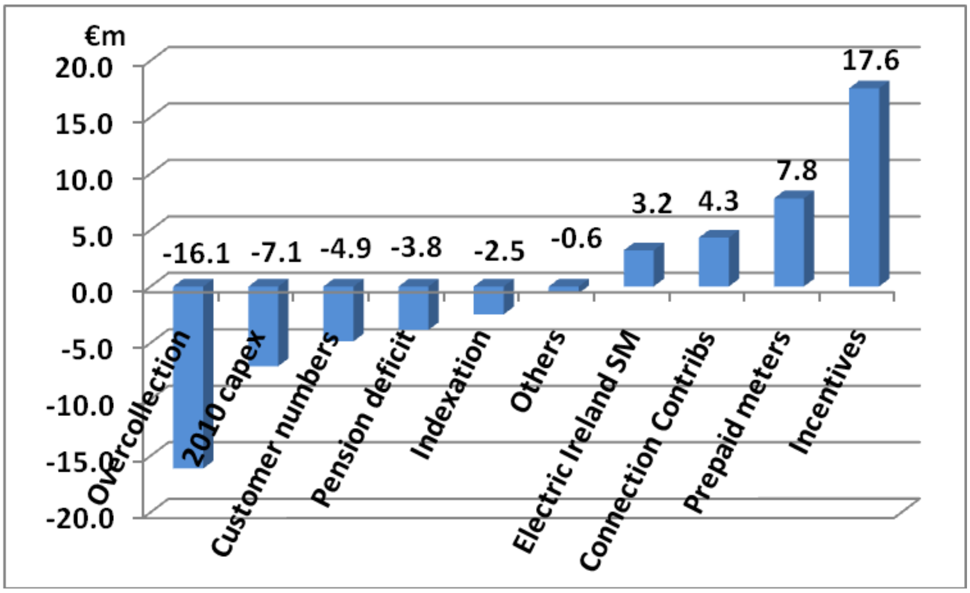

Figure 1: Adjustments to the base revenue allowed for 2012[9].

Pass-through costs

The figures for Insurance, rates, and ESI levy consist of the difference between the estimated figures that were allowed as part of the five-year revenue control and the out-turn figures for these items. The differences are passed through in whole. The values for 2012 (i.e. zero) correspond to the $\triangle P_t$ in Equation 1. The values for 2011 and 2010 are fed into Equation 1 through the k_{t-1} and k_{t-2} factors.

Uncertain costs

The uncertain costs included in Table 2 show the change in uncertain costs from those assumed in the five-year revenue determination. In some cases these costs/items were not mentioned within the five-year control as they were not examined/anticipated at that time.

The values for 2012 correspond to the $\triangle U_t$ in Equation 1. The values for 2011 and 2010 are fed into Equation 1 through the k_{t-1} and k_{t-2} factors.

These figures and the detail behind them have been reviewed by the CER and the CER is satisfied that they should be included within the DSO revenue for the 2012 calendar year.

A reduction of -€4.86m has been applied to the 2012 revenue to allow for a lower number of customer connections (-€2.71m) and non-repayable line diversions[10] (-€2.15m) relative to the previous forecasts.

[9] The ‘customer numbers’ value includes -€2.15m for non-repayable line diversion costs. ‘Other’ covers costs associated with insurance, rates and the CER levy (-€3.5m), ensuring non-quarterly-load profiles are correct (+€0.15m), the provision of ‘free’ moves from single to dual tariff meters (+€2.1m), an over-recovery relating to generator connections (-€0.5m), interest adjustments (+€0.4m) and RMDS.

[10] Non-repayable line diversions have been capitalised from 2011 onwards so there is only a 2010 adjustment here for this item.

The ‘pension deficit’ figures related to a pension deficit for ESB Networks’ distribution business as outlined in a CER decision paper published in October 2006[11].

The Retail Market Design Service (RMDS) is the ‘ringfenced’ function within ESB Networks responsible for all aspects of the retail electricity market design on behalf of the CER. The value included for 2010 is the difference between the total allowed cost and the outturn value. For 2011 onwards an allowance was made within the PR3 decision paper for the RMDS budget. The €0.8m included here for 2011 relates to new projects which were not included under this budget. These projects comprise a June 2011 retail market design upgrade which is mainly delivering the functionality to enable Global Aggregation on the retail side, and a harmonisation project which has been ongoing since 2009. The culmination of the harmonisation project will be a market design upgrade in September 2012. The details of this project are agreed through a harmonisation steering group which is a joint CER/NIAUR initiative. The costs included here are provisional and adjustments will be allowed for in subsequent years.

The figures for keypad and token meters include:

- €3.5m related to keypad meters. This is an interim prepayment solution in advance of the implementation of smart metering. This figure includes the costs of a project team (over 7 to 8 months) to coordinate development of the required market and business processes, procurement, testing, development and delivery of training for installation staff and call centre team, and communication with suppliers and customers. It also includes a cost of €2.0m for the procurement of 20,000 key pad meters
  The DSO has noted that it envisages that annual operating costs will be evaluated as the project progresses and advised to CER for inclusion in the next annual price review.
- €4.3m related to token meters. This covers the costs associated with the procurement of 16,557 token meters and the installation of 2,000 token meters in 2011 and recalibrations associated with these and existing token meters[12]. The 2,000 is an estimate and the actual amount installed will be allowed for through k factor adjustments.

A figure of €3.2m has been included to cover costs associated with Electric Ireland’s participation in ESB Networks’ smart metering trial[13].

[11] A document related to the CER’s decisions on 2007 allowed revenue and tariffs (CER/06/207) is available here.
[12] CER/10/203 (available here) states that the costs associated with the installation of new token meters and two recalibrations per annum for each token meter would be recovered through DUoS tariffs.
[13] Further information on this is provided in Appendix 3 of this information note.

The figure for load research (€0.15m) relates to the installation of additional Quarterly Hourly meters as part of the ongoing load profile research programme. Load profiles are updated every year for all of the Non Quarterly Hour customer groups. The DSO has noted that is a critical aspect of load metering to ensure that the standard load profiles adequately reflect the consumption of each customer group. It stated that this allowance will address the situation whereby due to change of business activities and ceasing of different businesses etc, the number of meters installed under a load profile research programme has decreased to unacceptable levels. It will allow the DSO to install 321 new meters over the next 18 months or so.

A figure of €2.08m has been included to cover the costs of customer moves from single to dual tariff meters. In the past the cost of a customer moving from a single to a dual tariff meter was recovered through a transaction charge to suppliers, which was then passed on to customers. However, since 2008 this cost is not (in most cases) recovered through a transaction charge. This figure covers the costs incurred by the DSO when accommodating 8,283 changes from single to dual tariff meters over the 2008 to 2010 period.

The figure of -€7.05m for adjustments regarding 2010 capex covers an underspend of 2010 network and non-network capex (relative to what was envisaged within the PR3 decision. It also allows for a carryover of some costs relating to smart metering (€4.5m), an Optimised Scheduling System (€2.3m), and investment in the training facilities and equipment infrastructure in the training centre in Portlaoise (€3.2m). These latter two items were envisaged to be completed in 2010, but the spend has now rolled into 2011. The outturn for all these items will be examined and any adjustments will be allowed for through a k factor. The -€7.05m also makes allowances for the actual number of new connections in 2010, and makes an adjustment for G2 and G3 costs which is consistent with the PR3 decision on these costs.

A figure of +€4.3m has been included to allow for an underrecovery of DSO revenue for customer connections related to the transition from the PR1 to PR2 period. This relates to the change in contribution rates from 45% to 50% between 2005 & 2006 and also allows for under-recoveries due to the manner in which customer payments and completion of work straddle both control periods.

A reduction of -€0.47m has been applied to the 2012 revenue to allow for over-recovery by the DSO with respect to generator connections. An examination of these costs has indicated that this difference is due to a mismatch between the timing of cost recovery and expenditure. This is discussed further in Appendix A of this paper.

Indexation and over collection

A reduction of -€18.59m has been applied to the 2012 revenue to allow for indexation being different to forecast (-€2.47m) and more revenue than forecast being collected over 2010 and 2011 through DUoS tariffs (-€16.12m).

Incentives

An incentive value of €17.55m is included in the above table. This relates to the 2010 calendar year; outturn values for 2011 are not available at this stage.

The €17.55m for 2010 includes values for Customer Minutes Lost (CML)[14] and Customer Interruptions (CI) that were calculated using the values in Table 3 below and incentive values applying to deviations from target levels, as detailed in Section 9.5, Table 10.4 of the 5-year electricity distribution revenue control[15].

	Forecast	Actual	Difference
Customer minutes lost	201	146	-55
Customer interruptions	171	143	-28

Table 3: *Target and actual figures for CML and CI*

The incentive figure of €17.55m for 2010 also includes a value for incentives relating to the DSO's customer call centre. In 2010, the DSO achieved a rating of 90% versus a target of 85%. This resulted in an incentive figure which would have exceeded the cap placed on this item[16]; therefore the figure was set at the cap, that is, 0.25% of allowed revenues or €1.70m. This is consistent with the decision paper relating to this incentive mechanism[17].

[14] Note that the incentive incentives for CMLs, CIs and losses are each capped to 1.5% of allowed revenue for the year.

[15] The decision on DSO revenue for the 2006 to 2010 period is available here.

[16] 4% multiplied by a PSATRAT of €0.650m; see the decision on quality of service incentive mechanisms during the 2006-2010 distribution price control (CER/06/107), available here, for more details.

[17] The decision on incentives for the 2006 to 2010 period relating to the DSO's customer call centre (CER/06/107) is available here.

3.3 Comparison with revenue for 2011 calendar year

The allowed DSO revenue for the 2012 calendar year is €721.6m, a 6.8% increase over the €675.7m that was allowed for the 2011 calendar year.

However, it is important to note that tariffs are not set on a calendar year basis. Consequently, interested parties may find it more useful to compare the AUP between tariff periods as discussed within Section 4 of this paper.

4.0 DUoS tariffs for 1 Oct 2011 to 30 Sept 2012

4.1 Revenue for recovery during Oct 2011 to Sept 2012

Section 2.3 provides detail on how portions of calendar year revenue are allocated for recovery within the DUoS tariffs that are implemented from 1 October to 30 September of a calendar year.

Continuing this methodology means that €180.4m (26.7%) of 2011 calendar revenue and €529.0m (73.3%) of 2012 calendar year revenue is allocated to the tariff period from 1 October 2011 to 30 September 2012. A total of €709.4m is therefore to be recovered during the 1 October 2011 to 30 September 2012 tariff period, a 4.8% increase relative to the €676.7m that was approved for recovery during the equivalent period for the previous year (1 October 2010 to 30 September 2011).

4.2 DUoS tariffs for Oct 2011 to Sept 2012

The DUoS tariffs for the 1 October 2011 to September 2012 period have been calculated by the DSO by essentially scaling up the existing DUoS tariffs to allow recovery of the revenue (given certain customer number and GWh assumptions) detailed in Section 4.2 of this paper (i.e. €709.4m).

These approved DUoS tariffs are published alongside this paper. If members of the public wish to compare these with previous DUoS tariffs, they can refer to the CER website for previous values[18].

While the DSO does not collect its revenue on a per kWh basis, it is sometimes useful to compare the Average Unit Price (AUP), that is, the total revenue divided by total kWhs, when moving from one tariff period to another. The AUP for the 1 October 2011 to 30 September 2012 tariff period is 3.05c/kWh, a 5.3% increase relative to the 2.90c/kWh for the previous tariff period.

A customer impact analysis showing the amount of DUoS paid by an average customer's (broken down by category) under the current and new tariffs is provided in Appendix B of this note.

[18] The tariffs that are currently in place (covering the period 1 October 2011 to 30 September 2012) are available here, underneath the consultation paper on DSO revenue.

5.0 Distribution Loss Adjustment Factors

The CER has approved Distribution Loss Adjustment Factors (DLAFs) for implementation from 1 October 2011 to 30 September 2012. These are published alongside this paper and are also provided below in Table 4.

The values for the period from October 2010 to September 2011 are available on the CER website[19] and have also been provided below within Table 5.

Voltage Level	Time Period		
	Composite	Day	Night
38kV Sales	1.017	1.018	1.014
MV Sales	1.038	1.040	1.032
LV Sales	1.084	1.089	1.072
Aggregate	1.072	1.076	1.061

Table 4: DLAFs for 1 October 2011 to 30 September 2012

Voltage Level	Time Period		
	Composite	Day	Night
38kV Sales	1.017	1.018	1.015
MV Sales	1.041	1.043	1.035
LV Sales	1.086	1.092	1.073
Aggregate	1.074	1.079	1.063

Table 5: DLAFs for 1 October 2010 to 30 September 2011

In relation to the improvement of figures compared with last year, the DSO has stated that the primary difference is a greater proportion of MV network operating at 20kV. The proportion of overhead MV network operating at 20kV is projected to increase significantly and go beyond 50% by the end of the PR3 period. This reduces the average MV network losses.

Two documents published in 2000 (a submission from ESB regarding the calculation of distribution losses[20] and a decision paper outlining the treatment of transmission and distribution losses[21]) provide background information in relation to losses and are available on the CER's website.

[19] The DLAFs for the current period (October 2010 to September 2011) are available here.
[20] A submission made by ESB in 2000 in relation to the calculation of DLAFs is available here.
[21] A CER decision in relation to the treatment of distribution losses is available here.

6.0 Summary

This decision paper outlines the CER's decisions on:

- The DSO allowed revenue approved for the 2012 calendar year;
- The DUoS tariffs approved for implementation during the tariff period from 1 October 2011 to 30 September 2012; and,
- The DLAFs approved for implementation during the period from 1 October 2011 to 30 September 2012.

The allowed revenue for the 2012 calendar year is €721.6.0m. This is a 6.8% increase over the €675.7m that was allowed for the 2011 calendar year.

The DUoS tariffs and DLAFs that have been approved for implementation during the period from 1 October 2011 to 30 September 2012 are published alongside this paper.

Appendix 1: Generator costs & charges

The decision on DSO revenue for the 2011 to 2015 period noted that the DSO expenditure on generator connections over the PR2 period (2006 to 2010) was €63.1m, but that €75.7m was collected in contributions, which is an over collection of €12.6m in the period. The DSO explained that the over collection relates primarily to expenditure incurred in PR1 and reflects the timing mismatch of expenditure and contribution. The CER stated within the decision that it would examine this matter further outside of the PR3 process.

Subsequently, the CER engaged with the DSO and the DSO provided the following note to explain the above over-recovery.

The CER agrees with the DSO proposal to reduce the RAB to allow for this over-recovery. The CER believes that this mismatch between contributions and expenditure will even out over time. However, the CER intends to completed a review of the standard prices (and measure them against outturn costs) once a sufficient number of projects have been completed.

Generation Connections
Variance between Contributions received & Costs incurred.

Background

The capital expenditure costs for Generation Connections for the 2006 to 2010 (PR2) period submitted to the CER as part of the ESB Distribution price control review for the 2011 to 2015 (PR3) period included a forecast of projected capital expenditure and capital contributions for 2010. The actual out-turn is reflected in the table below:

	Submitted	Actual
Costs	63.1	57.7
Contributions	70.8	60.1
	- 7.7	**- 2.4**

It has previously been indicated that in general, the nature of stage payments is such that timing differences between Price Review periods will arise. In addition, costs incurred at an early stage of a project are typically not assigned to that project until the receipt of capital approval, which is at the 55% construction stage. In order to show the variances that can occur in projects during a price review period, a review of projects was undertaken.

A sample of 20 projects which appeared to indicate that substantially higher costs were incurred than contributions received was examined. This sample gave a combined total expenditure of €39.5m during PR2 (68% of total generation connection incurred in PR2). The associated contributions received during the same PR2 period were €14.5m. This difference of €25.0m can be explained by a number of factors.

1. ***Higher Contributions received than costs incurred prior to PR2*** – A number of the projects within the sample were in progress prior to 2006. For these projects, the contributions received prior to 2006 were €6m greater than the costs incurred in the same period.

2. ***Shared Assets*** – Many of the projects are part of a group or cluster which contain shared assets. In the case of shared assets it is often the case that the shared asset will be constructed under one project. This can result in higher costs being incurred versus contributions received for that project. This is offset by lower costs being incurred in the remaining projects. In the sample selected, an adjustment of €7.6m should be made for costs incurred in these projects for shared assets.

3. ***TAO Costs*** – When a project has both a Distribution and Transmission element, the contribution is initially received by the DSO. This is then ultimately transferred to the TAO upon project completion. In the selected sample an adjustment of €0.4m should be made to the shared element of the costs for one project.

4. ***Reinforcement Costs*** – In the construction of Generation connections, additional system reinforcement works, which are undertaken at the most efficient time are often required. Also where a station was identified to be uprated in the future, a developer was only charged the brought forward costs of undertaking the uprate at that time. The additional costs should therefore be added to the RAB. In the projects selected, an adjustment of €3.0m is required.

5. ***Grid Upgrade Development Plan*** – €8.2m is GUDP related. Grants are due from the Department of Communications, Energy and Natural Resources in respect of the delivery of advance infrastructure. This money was expected in 2010 but has not yet been received, as such the costs associated with these grants were incurred during the price review period in question.

Cost €'m		Contributions €'m		Higher Contributions received pre PR2 €'m		Shared Assets €'m	TAO Costs €'m		Reinforcement Costs €'m		GUDP Grants €'m	Difference
39.5	-	14.5	-	6.0	-	7.6	0.4	-	3.0	-	8.2	0.7

As can be seen from the table, once the adjustments described above are made, the remaining difference reduces significantly to €0.7m.

Note:
Within the above sample, the six projects which were completed during the PR2 price review period indicated the % difference in spend versus contributions was only 2%.

To further show the variances that can occur in projects during a price review period, a second sample of 20 projects which appeared to indicate that substantially higher contributions were received versus costs incurred was also taken. The combined total contributions of this sample were €23.1m during PR2. The associated expenditure during the same period was €3.0m. This difference of €20.1m can be explained by a number of factors.

1. ***Higher Costs incurred than Contributions received prior to PR2*** – in the second sample selected, the costs incurred in the period prior to PR2 were €3m greater than the contributions received.

2. ***Shared Assets*** – A similar adjustment for shared assets (as made above) should be taken into account for this sample of projects. The adjustment in this case is €6.7m.

3. ***Second stage payment received Q3 and Q4 2010*** – As mentioned earlier, costs incurred at an early stage of a project are typically not assigned to that project until receipt of capital approval, which is at the 55% construction stage. For a large number of the projects in the sample, the construction stage payment was received in Q3 and Q4 2010. As a result, very few costs were assigned to those projects. An adjustment of €4.8m should be made to reflect this.

4. ***Changes made post offer acceptance and impact of long-lead time works*** – In relation to two specific projects contributions of €4.4m were received in PR2 with little associated costs incurred by the DSO. In one case this was due to the processing of a significant modification request which delayed construction. In the second case, group works on the Transmission System had a significantly longer lead time than the distribution works. In order to avoid the risk of stranded assets (in the event of a change to Transmission works) distribution works do not commence until there is more certainty in relation to the higher voltage works.

Cost €m	Contributions €m	Higher Costs Incurred pre PR2 €m	Shared Assets €m	Second Stage Payments €m	Post Offer Changes	Difference €m
3	-23.1	3	6.7	4.8	4.4	-1.3

As can be seen from the table, once the adjustments described above are made, the remaining difference reduces significantly to €1.3m.

Conclusion
Contributions and costs can vary during a particular price review period for a variety of reasons. As reflected above, these discrepancies can be explained by a number of reasons such as timing differences, shared assets and reinforcement work being carried out.

As a result of these factors and as consistent with the CER determination 2006 – 2010 ESB Price Control Review (CER 05/138) where it's stated "*with the introduction of the standard pricing regime, individual quotes will no longer be prepared, so any deviations between actual costs and contributions will be added to the RAB*"

It is proposed that the RAB be adjusted for the actual costs incurred and the actual contributions received at the end of every price review period. For the PR2 period this results in a reduction to the RAB of €2.4m (in 2009 money).

Appendix 2: DUoS payments made by average customer

The below table gives a customer impact analysis showing the amount of DUoS paid by an average customer's (broken down by category) under the current and new tariffs.

			DUoS payments made by average customer			
	kWh	MIC	Oct 10 – Sept 11 tariffs, €	Oct 11 – Sept 12 tariffs, €	Change, €	Change, %
DG1: Urban domestic - standard meter	3,954	n/a	176.9	188.6	11.7	6.6%
DG1: Urban domestic - dual meter	7,359	n/a	201.7	215.0	13.3	6.6%
DG2: Rural domestic - standard meter	4,226	n/a	209.6	223.4	13.8	6.6%
DG2: Rural domestic -dual meter	16,098	n/a	451.2	480.9	29.8	6.6%
DG3: Unmetered	24,141	n/a	639.5	681.7	42.2	6.6%
DG5 with a standard meter	11,706	n/a	484.4	516.4	31.9	6.6%
DG5 with a dual meter	44,512	n/a	1,309.2	1,395.8	86.6	6.6%
DG6	299,312	120	8,549.7	9,103.5	553.8	6.6%
DG7	3,268,946	980	18,656.2	19,895.5	1,239.3	6.6%
DG8	18,384,826	3,979	48,373.5	51,616.3	3,242.8	6.6%
DG9	1,532,069	360	8,361.7	8,917.6	555.9	6.6%

Appendix 3: Electric Ireland smart metering costs

In March 2007 the CER issued a Demand Side Management and Smart Metering Consultation Paper (CER/07/038) which was the first step in the the Smart Metering customer and technology behavior trials conducted over the period 2008 to 2010.

The overall smart metering project was managed by CER. The DSO installed the meters and the communications infrastructure. All of the customers in the residential trials, 6000 approx, were customers of Electric Ireland and a proportion of the SME customers were also Electric Ireland customers. Electric Ireland managed the communication with customers, implementation of Time of Use tariffs, new requirements for detailed billing and customer queries during the trials. As a result of this they incurred costs. The costs were agreed with CER in advance of the trial and only efficient costs directly attributable to the Smart Metering trial were included in the allowed costs. The final budget agreed in advance amounted to €5.4million.

As Electric Ireland had almost 100% of the domestic customer market and over 55% of the total market at the time the trial was planned and initiated it was intended that the costs incurred by Electric Ireland would be recovered through the regulated PES tariffs. Included in the Decision on ESB PES Allowable Costs (CER08152) for the 2009/10 tariff period was an allowance of €1million for the cost attributed to the Smart Metering trial and this amount was recovered through regulated tariffs.

Following the entry of Airtricity and BGE to the domestic retail electricity market in early 2009 Electric Ireland's share of the domestic market has dropped and is now below 60%. Their overall market share has also dropped below 50%. As a result it is no longer deemed appropriate to apportion all of the costs incurred by Electric Ireland as part of the SM trial to one group of customers constituting less than half of the market. It was therefore decided that it was no longer appropriate to recover the cost of the smart metering trial from Electric Ireland customers only.

DUoS charges were identified as the most appropriate means to recover the remaining costs as all customers will benefit from work undertaken as part of the Smart Metering trials. Table 1 below shows a breakdown of the costs to be included in DUoS tariffs. These costs are adjusted from the original budget of €5.4m to take account of cost previously recovered through regulated tariffs and interest over the period.

Resource Costs	2,805,495
IT Hardware & software	227,500
Communications &Marketing	342,675
Statistical Services & Customer Support	53,000
Incentives (to customers) and interest	869,923
SM Costs Recovered	-1,081,418
Total	**3,217,175**

Table 1: Electric Ireland’s Smart Metering costs for recovery through DUoS