ESB Customer Supply

Tariff Methodology Statement

For Tariff Period November 2007 to September 2008

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Appendices

1. Introduction

The purpose of the Tariff Methodology Statement is to set out clearly the methodology that ESB Customer Supply (ESBCS) uses to set retail tariffs. This Tariff Methodology Statement is approved by the Commission for Energy Regulation (CER).

1.1 Statutory and Licence Requirements

The functions of the Commission in relation to electricity are set down in Section 9 of the Electricity Regulation Act 1999 as amended by subsequent Statutory Instruments. SI 60 2005 {European Communities(Internal Market in Electricity) Regulations 2005} provides for the amendment of Section 9 of the 1999 Act for the purposes of assigning the Commission with the power to issue directions to ESB as the Public Electricity Supplier (PES) in relation to its costs, including tariffs. The legal basis for retail tariff regulation is also subject to EC Directive 2003/54/EC of the 23rd June 2003 which relates to the liberalisation of European energy markets.

ESB was granted an Interim Public Electricity Supply Licence in April 2006 (Ref. CER/06/073) and ESBCS carries out the role of the PES. Condition three of the interim licence 'Terms of Supply to Final Customers', outlines the obligations on ESBCS in relation to tariffs.

1.2 Purpose of Tariff Methodology Statement

The purpose of this Tariff Methodology Statement is to set out how ESBCS proposes to set tariffs for different customer groups for the period commencing from November 2007 to September 2008. This includes information on how costs are allocated to tariffs along with information on proposed changes to existing tariff structures and the formation of new tariffs.

1.3 General Principles

In line with the statutory and Licence obligations in relation to tariff setting, the key principles being applied in setting tariffs are centred around cost recovery, cost reflectivity and non-discrimination across customer groups. The main objectives for ESBCS in setting the tariffs are in:-

:

- *Achieving cost reflectivity and non-discrimination across all customer tariff groups.*
- *Providing appropriate economic price signals to customers.*
- *Delivering tariffs that are transparent, understandable and can be implemented.*

2 Background Assumptions for Tariff Calculations

This section discusses the approach to arriving at the customer demand forecasts that are used to determine the projected costs and revenues for the tariff period. While such forecasts might be discussed and presented in aggregate annual terms of customer consumption and/or demand growth rates at the retail level, they must be provided to a half-hourly granularity for the purposes of projecting ESBCS costs in the wholesale market.

2.1 Demand Forecasting

A combination of ‘top-down’ and ‘bottom-up’ forecasting techniques are used with up-to-date inputs from the customer billing and market settlement IT systems to provide a reference-case, central scenario.

- The ‘top-down’ approach starts with a forecast of total consumption in the market and arrives at the ESB CS forecast by considering ESB CS projected market share .
- The ‘bottom-up’ approach produces a forecast for each tariff group. These are then summed to arrive at the forecast of ESBCS overall consumption.

2.1.1 Market Consumption

Total Final Consumption (TFC) in the RoI market comprises ESBCS consumption, independent supplier consumption and the local own-use of CHP or small-scale generation plant. As noted in EIRGRID’s Generation Adequacy Review, this own-use or self-generation represents approximately 2% of system demand.

The baseline for projections (currently TFC in 2006) is derived from published system demand and settlement quantities and the estimation of own-use. Forecasts are then produced using established techniques, as discussed below.

The primary driver of electricity demand growth has traditionally been shown to be the performance of the country’s economy and it has become standard international practice to use Gross Domestic Product (GDP) as the causal input to the electricity demand forecast model. While this will establish a standard forecast, we must also have regard to the myriad of uncertainties which impact on demand and their potential to introduce step changes over the forecast period.

Such uncertainties, affecting electricity usage, include :

- Any change in the relationship of demand drivers (GDP) with final demand
- National economic climate subject to change within a year
- Population growth and house-build
- Structural growth (residential/commercial/industrial)
- Impact of lifestyle changes on customer consumption levels
- Public perception (e.g. environmental & conservation considerations)
- Take-up by customers of new technologies or products
- Impact of fuel availabilities & prices
- Weather and other short-term significant events (e.g. live-TV) which will affect half-hourly demands but are not explicitly catered for in the Pricing timeframe.

These considerations notwithstanding, forecasts of TFC for future years are derived using a ‘top-down’ approach with GDP as the single causal input. This is characterised by the application of standard regression analysis to historic pairs of annual TFC and corresponding GDP values to give average annual growth rates over the planning period. Projections of GDP correspond to the ESRI forecast of their most recent 'Medium Term Review'. The resultant demand forecasts are then typically tested for reasonableness by comparison with those provided in the System Operator's most recent Generation Adequacy Review. Where it is judged necessary, the forecast may be adjusted to take account of revised assumptions generated by any of the uncertainties listed above.

2.1.2 ESB CS Market Share

A 'top-down' analysis approach is again used to provide an initial global estimate for ESBCS share of this forecast market TFC. Obviously, this share will depend on the activity of independent suppliers in the market, and the primary determinant of this will be their access to generation.

The 'bottom-up' analysis allows us to make explicit assumptions to give a more detailed view. In this 'bottom-up' approach forecasts are produced for each tariff group, which are then summed to arrive at the forecast of ESBCS overall consumption.

This entails setting out assumptions with regard to expected customer movements for each customer tariff category taking into account both new connections and movements to and from other suppliers, as well as the appropriate sizing of each of these customer tranches. The resultant forecasts from the 'top-down' and 'bottom-up' approaches are then reconciled to give the required central projection of ESBCS customer numbers and consumption for the tariff period.

2.1.3 ESBCS Demand Volume and Shape

The above customer consumption forecasts at the retail level are translated into corresponding forecasts of wholesale energy purchase requirements at the half-hourly level. There is therefore a shape element as well as a volume element to the projections.

ESBCS's wholesale electricity demand for settlement purposes is derived as the difference between the total of electricity consumed on the system and that supplied by independent suppliers. This may differ from the wholesale demand calculated by application of standard tariff profiles and network loss factors to the associated retail consumption (in common with other suppliers). Adjustments of selected tariff profiles can be made to achieve a better fit for historic values, but this is not the enduring solution which will be provided by the introduction of global aggregation.

Obviously, the shape of our wholesale demand forecasts will become an increasingly important factor with the advent of the SEM, since they will essentially determine our optimised portfolio of hedge contracts and pool purchases.

3 Tariff Cost Elements

There are four main tariff costs elements.

1. Energy Wholesale Costs
2. Network Charges
3. Supply Costs
4. Public Service Obligation Levy

3.1 Energy Wholesale costs

Energy is purchased at the wholesale level to meet Customers' energy demand and the energy losses that occur transporting the energy directly to the customer.

The largest component of Energy wholesale costs is the cost of electricity purchased in the Pool at prices which reflect the market value of wholesale electricity (which in turn are expected to reflect the marginal costs of the marginal generator). This component is often referred to as the System Marginal Price (SMP).[1] The second largest component of Electricity Wholesale costs is the Capacity Payment Mechanism costs which is the fixed costs associated with having generator plant available to provide electricity to the pool. The other pool related costs are the market operator costs and imperfection charges.[2]

This SMP varies from half-hour trading interval to half-hour trading interval. To stabilise the price of electricity over a period, ESBCS enters into Contracts for Differences (CfDs) with generators. Stabilising the price at which energy is bought in the Pool is known as "hedging" or "contracting" and may bring an additional cost (or produce a discount) relative to the SMP.

The wholesale energy purchased is to meet ESBCS customers' demand and to provide for energy losses in the transmission and distribution of that energy to the final customers. Almost all the energy for ESBCS customer demand and transportation losses is purchased in the Pool (except for energy from generators < 10MW).

ESBCS Energy Wholesale costs for 1 November 2007 to 30 September 2008 can be categorised as follows:

- Pool Energy Costs (SMP) and Contract Costs (Premia relative to SMP)
- Generator Capacity Payment Mechanism Costs
- Market Operator Costs
- "Imperfection" Costs

Contract Premia may include

- Public Service Obligation (PSO) Energy Contract Costs
- "Directed" Energy Contract Costs
- "Non-Directed" Energy Contract Costs (hedges)

where these contracts costs are different to the SMP.

[1] To help to minimise any possible confusion, this document will use the term SMP when referring to the marginal cost of electricity as purchased from the pool.
[2] This document will refer to unhedged Wholesale Pool Price as the "Consolidated Pool Price" (CPP). CPP = SMP + Capacity Payment Price + Market Operator Price + Imperfection Price.

3.1.1 Pool (SMP) and Contract Costs

The Electricity Pool defines the market trading rules and procedures for buying or selling wholesale electricity. All energy from generators > 10MW is purchased by Suppliers via the Electricity Pool. The Pool facilitates a competitive bidding process between generators that sets the wholesale price paid for electricity for each half hour period of every day and establishes the preferred generation merit order at the day ahead stage. The pool price is known as the “System Marginal Price” (SMP).

The Electricity Pool SMP price is the driver of wholesale electricity costs.

Because the SMP varies and can be volatile suppliers and generators can enter financial contracts (hedges) to fix or stabilise the cost of the energy between them. There may be premia or discounts relative to the (forecast) pool price that arise from hedging. These should be relatively small given the existence of a separate capacity payment for generators and the desire for both suppliers and generators to have certainty about costs and revenues over the contracting period.

As ESBCS offers regulated fixed tariffs, it has as a key objective to hedge its exposure to the variable SMP (i.e. fix its input energy costs) to the extent that it is economic to do so.

In each half-hour trading period, where ESBCS is “under-hedged” it buys electricity from the pool at the pool price to meet its aggregate customer demand requirement. When ESBCS is “over-hedged” it effectively “sells” electricity back to the pool at the pool price.

3.1.1.1Contract Costs

The “actual cost” of all contract types is the difference between the “strike price” of the contract and the outturn SMP – i.e. the incremental difference relative to the outturn pool price. (The forecast “cost” is relative to the “forecast SMP”). This cost is also known as the “hedging premium” (although in some cases it may be a “negative cost” i.e. a discount.

There are three different types of contracts that ESBCS will enter into for the period 1 November 2007 to 30 September 2008 based on the nature of the contract and the counterparty.

(1) Directed Contract Costs

These contracts are Contracts for Differences (CfDs) entered into with ESB Power Generation and purchased during the directed contract auction process between June to mid-July 2007.
The directed contracts are defined standard contracts

- in the form of either baseload, mid-merit or peak “block” contracts
- Quarterly contracts
- same volume in each month of the Quarter

(2) Non-Directed Contract Costs

These contracts are Contracts for Differences (CfD's) or other contracts entered into with different power generators / brokers / financial houses in particular with ESBPG and NIE PPB through the FAXboard auction process for 3 weeks from 30 July 2007.

(3) Public Service Obligation (PSO) Contract Costs

These contracts are for the provision of indigenous or environmentally friendly forms of electricity or for security of supply reasons in RoI. ESBCS can bid for the PSO contracts which will be offered to the market in an auction organised by ESBPG.

If the actual costs for the PSO contracts in aggregate (including peat-fired generation) are greater or less than the PSO contracts at the benchmark cost, the difference is debited or credited to all electricity customers in the Republic of Ireland as the PSO Levy (See 3.4).

3.1.2 Capacity Payment Mechanism Costs

The Capacity Payment Mechanism (CPM) under the Single Electricity Market (SEM) is a mechanism which allocates an amount of money (the Annual Capacity Payment Sum[3]) determined prior to the start of each year into monthly amounts and is paid to Generators based on their availability in each half-hour.

CPM costs are allocated to all ESBCS customers, regardless of tariff category, on the same €/MWh basis (at the trading point) in each trading period.

The overall CPM costs for each customer will depend on the overall demand profile for that customer i.e. the level of demand and the coincidence between the customer's demand and the system demand.

The actual CPM cost in each trading period (in €/MWh) will not be known until ex-post. However ESBCS believes that it is possible to forecast the CPM cost curve for input to the tariffs (See 5.1.3).

3.1.3 Other Energy Market Costs

Market Operator charges (the costs of operating the pool market) and Imperfections charges (which include transmission congestion charges and currency charges) are other market costs that will be included in the final retail tariffs. These costs will be fixed for the tariff year November 2007 to September 2008 and will be allocated to customers on a demand (i.e. per MWh) basis.

It is worth noting that contract costs may also have duel indexation provisions and exchange risks that need to be hedged separately.

[3] Determination of the annual sum is based on the product of two numbers:
• A volume element (the Capacity Requirement) - the quantity of capacity required to just meet an all-island adequacy standard; and
• A price element – the fixed costs of a Best New Entrant (BNE) peaking plant.

3.2 Network Charges

These are the energy transportation costs or the “toll” associated with transporting energy from the point of purchase (trading point) to point of sale (customer point). Costs arising from the use of the transmission and distribution networks follow from the regulatory approved tariffs ie the Transmission Use of System Charges (TUoS) and the Distribution Use of System Charges (DUoS) which are published annually in advance of tariff setting.

3.3 Public Electricity Supply (PES) Costs & Margin

ESBCS is the licensed PES in the Republic of Ireland. ESBCS costs & margin have been approved by the Commission in the 2006-2010 ESB Price Control Review - Public Electricity Supply ref CER/05/164. The allowed revenue comprises operating expenditure (opex), depreciation charges on capital expenditure (derived from the allowable capex) as well as the permitted margin. Allowed revenue also reflects a customer service incentive payment or penalty linked to the performance of the Customer Contact Centre. Operating expenditure was approved under specified headings including payroll, bad debt provision, shared service costs, contact centre operations etc.. Further detailed information on the allowed revenue is available in the above document, ref CER/05/164, Table 3.2 Opex Allowed Decision.

The approach taken by the Commission in approving the allowed costs for the period 2006 – 2010 was to set allowed costs for a base year and thereafter to link changes in allowed costs to inflation. .

3.4 Public Service Obligation Levy Costs

The PSO was first imposed by the Minister for Communications, Marine and Natural Resources on the Electricity Supply Board (ESB) on 1st January 2003 and has been amended from time to time since. It requires ESB to purchase power from specified sources, including, but not limited to, peat, renewable and other sustainable sources. The Act specifies four areas which the PSO can cover:

(a) security of supply,
(b) regularity, quality and price of supplies,
(c) environmental protection, and
(d) use of indigenous energy sources.

The Commission for Energy Regulation (CER) is required to calculate and notify all relevant parties of the level of the Public Service Obligation (PSO) levy each year in accordance with section 39 of the Electricity Regulation Act 1999 (the Act), (Public Service Obligations) Order 2002 (SI 217 of 2002) as amended.

For customers with an MIC < 30kVA, the PSO Levy is charged on a fixed cost per customer basis.
For customers with an MIC > 30kVA, the PSO Levy is charged per kVA.

For 2007 the CER has set the PSO Levy to zero. The 2008 PSO Levy has not yet been set by CER and a determination is expected at the end of July 2007.

4 Customer Groupings

4.1 Tariff Classes

The grouping of customers for tariff purposes was fundamentally based on customer type; Domestic, Small Commercial and Large Commercial & Industrial Customer. Historically, this classification was the obvious one because each customer type had a different consumption level range and thus metering arrangement, a different service level expectation and an appropriate tariff complexity level.

Within each of these Customer type groupings, there are different sub-tariff categories.

The main Tariff Classes and Sub Tariffs are as follows:

Domestic tariffs: Urban 24 Hour, Urban Nightsaver, Rural 24 Hour, Rural Nightsaver

Small Commercial Tariffs: General Purpose 24 Hour, General Purpose Nightsaver, Residential Business Premises 24 Hour, Residential Business Premises Nightsaver, Low Load Factor Tariff, Low Voltage Maximum Demand.

Large Customer Tariffs: Medium Voltage (10kV/20kV) System Time of Day (STOD)[4], 38kV System Time of Day (STOD), 110kV System Time of Day (STOD).

In establishing discrete tariff groupings, there are trade-offs to be made e.g.

- trade off between the number of tariff classes and the degree to which the tariff reflects the costs associated with that particular group of customers.
- trade off between the simplicity i.e. ease of understanding of a tariff and the degree to which the tariff can accurately reflect the costs associated with that particular group of customers & provide economic signals

The key technical limitation for the sophistication of tariff that can be implemented for any customer type is the sophistication of the metering arrangement (See Section 4.3).

For the tariff period commencing November 2007, ESBCS believes it is appropriate to retain the existing tariff categories and structures with the exception of the tariffs for LEU customers. A pool price pass through tariff will be implemented for LEU customers from November 2007.

More details of ESBCS's tariff groupings are set out in Appendix 1 and Appendix 2.

[4] The STOD tariff replaced the Maximum Demand tariff for Large Energy Users (LEU) customers at Medium Voltage, 38kV and 110kV on 1 January 2007. This was made possible by the recent introduction of Quarter Hourly metering (QH metering) for these customers.

4.2 Load Research

The forecast energy demand profiles used to forecast demand shape (load shape), which is the determinant of energy and network costs, for the different customer groups are as follows:

Tariff Group	**Forecast Demand Profile to be used**
Urban Domestic 24-Hour Customers	Industry Standard profile (LP1)
Urban Domestic Nightsaver Customers	Industry Standard Profile (LP2)
Rural Domestic 24-Hour Customers	Industry Standard Profile (LP3)
Rural Domestic Nightsaver Customers	Industry Standard Profile (LP4)
General Purpose 24 Hour	Industry Standard Profile (LP5)
General Purpose Nightsaver	Industry Standard Profile (LP6)
Residential Business Premises 24 Hour	Industry Standard Profile (LP5)
Residential Business Premises Nightsaver	Industry Standard Profile (LP6)
Low Voltage Maximum Demand	Sampled Actual Customer Profiles, scaled to forecast demand
Low Load Factor	Industry Standard Profile, (LP7) LF < 30%
10kV / 20kV STOD	Individual Customer Actual Demand Profile (Pool Price pass through)
38kV STOD	Individual Customer Actual Demand Profile (Pool Price pass through)
110kV STOD	Individual Customer Actual Demand Profile (Pool Price pass through)

- The industry standard profiles are provided by ESB Networks (Profile Data Services) and are updated annually.

4.3 Metering Arrangements

The metering employed for different customer classes is determined at present by ESB Networks. The present criteria for the installation of QH meters is:

- Customer annual consumption > 300MWh
- Existing Customers with MIC > 100kVA
- All new customers > 50kVA

The QH meter functionality by tariff group is as follows:

	Quarter Hourly Meter
Domestic 24 hour Customers	0%
Domestic Dual Tariff Customers	0%
General Purpose Customers	0%
General Purpose Dual Tariff Customers	<1%
LV Maximum Demand Customers	30% approx.
10kV / 20kV Customers (STOD)	100%
38kV Customers (STOD)	100%
110kV Customers (STOD)	100%

5 Tariff Formulation

5.1 Cost Attribution to different Customer Categories

5.1.1 Allocation of Wholesale Energy Costs

For the first year of SEM ESBCS will purchase wholesale energy for its portfolio of customers as follows:

1. LEU Customers (Customers supplied at 10kV and above)
ESBCS will charge these customers transparently based on the actual Consolidated Pool Price. These customers will be on a “Pool Price Pass through Pricing Structure” and will be exposed to the SMP in each half-hour trading period.

Energy losses will be allocated according to published Distribution Loss Adjustment Factors (DLAFs) depending on the voltage level at which customers are supplied.

See Appendix 3 for Details on Proposed Pool Price pass through Pricing Structure from the 1st November 2007.

2. Fixed Tariff Customers (i.e. all Customers supplied at Low Voltage – residential and small business customers).
ESBCS will enter into contracts for the majority of the energy for these customers and will purchase any residual amount of energy required to meet their demand directly from the pool. The energy contracts for these customers will be PSO Contracts, Directed Contracts and Non-Directed Contracts. ESBCS aims to optimise the mix of contracts and pool purchases so as to minimise cost and provide maximum cost stability.

Allocation of Wholesale Pool Energy Costs for Fixed Tariff Customers

Energy purchases are optimised on a portfolio basis for fixed tariff customers i.e. the purchase of hedges is optimised for the overall demand of all fixed tariffs together rather than for any tariff individually.

In order to reflect pool market energy cost signals in its tariffs, flat contract costs will be modified to provide day/night & seasonal price signals to customers.

This will mean that the SMP cost signal will be reflected with minimum distortion in the generation costs allocated to each tariff and therefore in the final tariff price.

5.1.2 Allocation of Capacity Payment Mechanism Costs

Capacity Payment Mechanism (CPM) charges to suppliers are settlement period specific (monthly pots), will be in €/MWh at the trading point and will be calculated separately for each trading period i.e. CPM supplier costs can be represented by a forward cost curve proportional to demand.

The CPM cost in €/MWh in any trading period =
[[Monthly System CPM Pot] * Demand Scaling factor (for the period) * Price Scaling Factor(for the period] / System Demand (for the period)

Essentially the monthly CPM cost is profiled over trading period in the month by a demand scaling factor which allocates the cost over the trading periods according to a “peakier” version of the system demand profile.
The price scaling factor usually is very close in value to 1 and so has little impact except in exceptional cases where the System Marginal Price (SMP) is very high and approaches the Value of Lost Load (VOLL which is expected to be in the region of €7,000/MWh). Put another way, the price scaling factor dampens CPM costs during trading periods when SMP prices become exceptionally high.

The CPM cost (in €/MWh) in each trading period will be the same for all suppliers. A supplier’s overall CPM charges (in €) will depend on the suppliers aggregate demand profile. The main determinant of a suppliers overall capacity payment charges is the level of demand in each trading period and then by the coincidence between the suppliers demand and the system demand.

The overall CPM costs for each customer will depend on the overall demand profile for that customer i.e. the level of demand and the coincidence between the customer’s demand and the system demand.

The actual CPM cost in each trading period (in €/MWh) will not be known until ex-post.

The formulae for calculation of Supplier CPM charges are given in the Section 4 of the SEM Trading & Settlement Code.

CPM costs are allocated to all ESBCS customers, regardless of tariff category, on the same €/MWh basis (at the trading point) in each trading period.

5.1.3 Allocation of Other Market Costs

Market Operator charges and imperfections charges (which include transmission congestion charges and currency charges) are other market costs that will be included in the final retail tariffs. These costs are set ex-ante and are published in advance of tariff setting by CER. They will be allocated to customers on a demand (i.e. per MWh) basis.

5.1.4 Allocation of Network Charges

Costs arising from the use of the transmission and distribution networks follow from the regulatory approved tariffs ie the Transmission Use of System Charges (TUoS) and the Distribution Use of System Charges (DUoS) which are published annually in advance of tariff setting.

Network Charges have a number of components; some or all of the following depending on the DUoS or TUoS Group:

Fixed charge / customer; kWh; kW(Contracted Maximum Import Capacity), kW (Excess Contracted MIC), Excess kVARh. All quantities are metered at the customer’s terminals.

5.1.5 Allocation of Supply Costs

The allowed operating expenditure is attributed to tariffs linked to cost to serve per customer per tariff type and the customer numbers in that tariff category.

The PES Allowed Revenue for 2007/08 will determine the allowed Supply costs . These allowed costs will be allocated across the tariff customer categories. Customers will be charged a fixed supply charge which is the average supply cost for their particular tariff group (€/customer).

Allowed Margin is set at 1.3% of total revenue in accordance with the Commission's determination (AIP/SEM/304//07) and this is attributed to tariffs based on the percentage of electricity Sales Revenue per tariff type.

5.1.6 Allocation of Public Service Obligation Levy Costs

The Commission for Energy Regulation (CER) is required to calculate and notify all relevant parties of the level of the Public Service Obligation (PSO) levy each year in accordance with section 39 of the Electricity Regulation Act 1999 (the Act), (Public Service Obligations) Order 2002 (SI 217 of 2002) as amended.

For 2007 the CER has set the PSO Levy to zero. The 2008 PSO Levy has not yet been decided and published by CER.

For customers with an MIC < 30kVA, the PSO Levy is charged on a fixed cost per customer basis.
For customers with an MIC > 30kVA, the PSO Levy is charged per kVA.

These costs are calculated and specified by CER and levied on all electricity customers in the Republic of Ireland. (The same levy is charged collected by all suppliers).

5.2 Revenue Correction Mechanism

While ESBCS is committed to ensuring compliance with best practice hedging and forecasting methodology, ESBCS will continue to have variances between the forecast costs and the actual costs due to changes in customer demand and/or variances in costs. In order to address this situation an Ex-post Revenue Correction Mechanism will be applied as follows:-

- For customers other than LEU customers, if forecast variances between costs included in the tariffs and revised forecast costs during the year exceed a threshold the tariffs will be subject to review. Where tariff rates are to be revised, they will be revised for the remainder of the tariff year to reduce the end-of-year variance. The procedure for implementing such an adjustment is to be agreed with CER.

- Over and above this, cost variances below the threshold will be catered for in a year end adjustment and consequently, incorporated into the tariffs for the following year.

- For LEU customers (10kV, 20kV, 38kV & 110kV) a pool price pass through pricing structure will apply and therefore no revenue correction mechanism is envisaged. These customers will be charged based on Actual Energy Costs (Actual CPP) + tariff for non-energy charges[5].

5.3 Tariff Structures

The domestic tariffs, general purpose tariffs, residential business premises tariffs and maximum demand tariff structures are almost unchanged for over a decade.

<u>Innovation in Electricity Tariff Structures</u>

Two new tariff structures have been introduced in the last 18 months to be more reflective of underlying costs.

- In 2006 a 7-band STOD tariff was introduced for LEU customers replacing the MV, 38kV and 110kV Maximum Demand tariffs. This was made possible by the introduction of QH metering for this group.

- In 2006, a new tariff the Low Load Factor tariff was introduced for low load factor customers with MIC > 50kVA as an alternative to the maximum demand tariff.

A pool price pass-through tariff is proposed for LEU customers from 1 November 2007.

The existing tariff structures and any tariff changes are approved annually by CER as part of the CER's annual price determination.

It is worth noting that changes have been introduced with the approval of CER in recent years to improve tariff cost reflectivity.

For example
- Excess Capacity Charges for LVMD and for LEU customers are now cost-reflective of the DUoS Excess capacity charges (since July 2006)
- The RBP tariffs have had the second block threshold reduced to better reflect the underlying DUoS charge.
- Customers with MIC > 50kVA can no longer become general purpose customers as the GP tariff is mapped to the DG5 DuoS group (since 2005).
- Low power factor surcharge in the retail tariffs is now cost reflective of the DUoS charges (since 2006).

[5] The mechanism on how wholesale costs will be reflected in the Pool price pass-through tariffs for LEU customers is expected to be consulted on in August 2007.

ESBCS is closely monitoring developments in “Smart metering” and aims to develop tariff options to maximise the impact and benefits of this emerging technology.

See Appendix 4 for detail on Tariff Structures.

6 Policy Objectives

The objective in setting the tariffs has been to comply with the conditions set out in ESBCS's supply licence in relation to tariff setting.

6.1 Supplier of last resort

The Commission's decision on the Supplier of Last Resort in Electricity ref CER/06/006 sets out the appointment of ESBCS as the supplier of last resort (SoLR). Section 2 and Section 7 of this decision paper contain the duties of the SoLR and the relevant points regarding cost recovery. In respect of tariffs the key points which are to be taken into account by ESBCS are from Section 2, viz:

- (d) to maintain normal conditions of supply for 6 months after the SoLR event for customers on the SoLR tariff or until customers are registered on a different tariff or to a different supplier.
- (f) after 6 months transfer the remaining SoLR customers from the SoLR tariff onto a regular tariff that is appropriate to their customer category.

From Section 7:

- Non-energy costs (for inclusion in the SoLR tariff) will be agreed and included ex-ante and energy costs will be estimated ex-ante and adjusted ex-post
- The ex-post adjustment which will include energy and non-energy costs and subject to Commission approval will be made via the TUoS charge
- The structure and level of the SoLR tariff will correspond to the standard (regulated) tariff for the customer category.

In its decision CER also stated that the SoLR is required to advise CER of its plans to procure energy for the SoLR customers and that separate books of account are to be kept for SoLR customers.

ESBCS understands that it follows from this decision that SoLR customers will be charged tariffs that directly reflect the cost of supplying them and that correspond to the normal tariff for their customer category. For example, the SoLR tariff structure for domestic customers would be the same as the current domestic tariff and MVMD (SoLR) customers would see the proposed pool price pass through tariff.

ESBCS would propose to follow the same methodology in the allocation of SoLR costs to SoLR customer tariff categories as for non-SoLR customers. The only differences being that:

- different costs are used e.g. ex-ante estimates of both energy and non-energy costs which are driven by the SoLR event
- there is a specified mechanism for recovery of the difference between the ex-ante estimate and the ex-post actual costs.

6.2 Universal Supply Obligation

The legal basis for the Universal Service Obligation (USO) is set out in Section 18 of SI 60 of 2005 which states that 'the PES (ESBCS) shall meet all reasonable requests to supply electricity and that the Commission may specify the terms and conditions under which such a request may be considered unreasonable. Condition 8 of the PES Interim Licence further confirms this obligation.

In practice this obligation means that ESBCS has a duty to meet all requests for supply on the tariffs and standard terms and conditions approved by the Commission under the PES Interim Licence. In so far as ESBCS will continue to be regulated with the continuation of the USO in mind, we do not envisage that there needs to be a change in this approach i.e. tariffs are developed and approved in the knowledge that ESBCS has this universal service obligation and that the costs arising from meeting this are recoverable through the tariffs or an alternative mechanism to be agreed with CER.

6.3 Energy Efficiency

ESBCS retail tariffs have been designed to give appropriate price signals to incentivise customers to shift demand from expensive consumption periods to less expensive consumption periods. In particular ESBCS provides domestic and general purpose “nightsaver” options whereby customers who pay a higher standing charge can benefit from lower night rate electricity prices. The introduction of the STOD tariff to large electricity users (LEU) in 2007 has given a clear price signal to these customers to encourage load shifting from peak times.

Energy efficiency tariff options are largely determined by the metering available. The introduction of smart metering for domestic customers will facilitate further pricing incentives to encourage load management at peak times.

6.4 Network Related Transaction Charges

In line with CER’s decision for ESBCS to charge customers directly for a number of specified and published network related transactions e.g. check meter readings, de-energisations, ESBCS introduced this charging mechanism from January 2007. The costs associated with these Network related activities are now being recovered directly from customers. .

Appendix 1

ESB Customer Supply - Customer Tariff Categories

Customer Category	Main Tariff Category	Tariffs
DOMESTIC	Domestic Rural Domestic Urban	Domestic Urban 24Hr Domestic Urban N/S Domestic Rural 24Hr Domestic Rural N/S
SMALL BUSINESS	Residential Business Premises General Purpose	Res Bus Prem 24Hr Res Bus Prem N/S GP 24Hr NQH GP N/S NQH GP 24h QH GP N/S QH
MEDIUM ENTERPRISES	Max Demand Low Voltage LV LOW LOAD FACTOR	LVMD (NQH & QH) LLF (NQH & QH)
"LARGE ENERGY USERS"	MV (10/20kV) STOD 38 KV Tailed STOD 38 KV Looped STOD 110 KV STOD	10/20kV STOD 38_kV Tailed STOD 38_kV looped STOD 110_kV STOD
PUBLIC LIGHTING & Miscellaneous Supplies	Metered Public Lighting* Unmetered Public Lighting Unmetered Single Point	Public Lighting - Metered PL Public Lighting - Unmetered PL - 24 Hou Public Lighting - Unmetered PL - Dusk to Midnight Public Lighting - Unmetered PL - Dusk to Unmetered Single Point

*Restricted Tariff

Appendix 2

ESB (Public Electricity Supply) Electricity Tariffs 2007

Urban Domestic				
Standard Tariff				
Tariff Components		**Price per Unit**	**Annual Price**	**Daily Price**
Standing Charge	per annum, pro-rated daily		€87.60	€0.2400
Unit Rate	per kWh	€0.1435		
PSO	per month end		€0.00	

Urban Domestic				
Nightsaver Tariff				
Tariff Components		**Price per Unit**	**Annual Price**	**Daily Price**
Standing Charge	per annum, pro-rated daily		€140.16	€0.3840
Unit Rate Day	per kWh	€0.1435		
Unit Rate Night	per kWh	€0.0705		
PSO	per month end		€0.00	

Urban Domestic				
Night Storage Heating				
Tariff Components		**Price per Unit**	**Annual Price**	**Daily Price**
Standing Charge	per annum, pro-rated daily		€8.03	€0.0220
Unit Rate	per kWh	€0.0705		

Urban Domestic Group Account				
Standard Tariff				
Tariff Components		**Price per Unit**	**Annual Price**	**Daily Price**
Standing Charge	per annum, pro-rated daily		€87.60	€0.2400
SC per each add. Flat	per annum, pro-rated daily		€38.69	€0.1060
Unit Rate	per kWh	€0.1435		
PSO	per month end		€0.00	

Urban Domestic Group Account				
Nightsaver Tariff				
Tariff Components		**Price per Unit**	**Annual Price**	**Daily Price**
Standing Charge	per annum, pro-rated daily		€140.16	€0.3840
SC per each add. Flat	per annum, pro-rated daily		€85.41	€0.2340
Unit Rate Day	per kWh	€0.1435		
Unit Rate Night	per kWh	€0.0705		
PSO	per month end		€0.00	

Rural Domestic				
Standard Tariff				
Tariff Components		**Price per Unit**	**Annual Price**	**Daily Price**
Standing Charge	per annum, pro-rated daily		€116.80	€0.3200
Unit Rate	per kWh	€0.1435		
PSO	per month end		€0.00	

Rural Domestic				
Nightsaver Tariff				
Tariff Components		**Price per Unit**	**Annual Price**	**Daily Price**
Standing Charge	per annum, pro-rated daily		€177.39	€0.4860
Unit Rate Day	per kWh	€0.1435		
Unit Rate Night	per kWh	€0.0705		
PSO	per month end		€0.00	

Rural Domestic				
Night Storage Heating				
Tariff Components		**Price per Unit**	**Annual Price**	**Daily Price**
Standing Charge	per annum, pro-rated daily		€8.03	€0.0220
Unit Rate	per kWh	€0.0705		

Rural Domestic Group Account				
Standard Tariff				
Tariff Components		**Price per Unit**	**Annual Price**	**Daily Price**
Standing Charge	per annum, pro-rated daily		€116.80	€0.3200
SC per each add. Flat	per annum, pro-rated daily		€66.43	€0.1820
Unit Rate	per kWh	€0.1435		
PSO	per month end		€0.00	

Rural Domestic Group Account				
Nightsaver Tariff				
Tariff Components		**Price per Unit**	**Annual Price**	**Daily Price**
Standing Charge	per annum, pro-rated daily		€177.39	€0.4860
SC per each add. Flat	per annum, pro-rated daily		€122.64	€0.3360
Unit Rate Day	per kWh	€0.1435		
Unit Rate Night	per kWh	€0.0705		
PSO	per month end		€0.00	

General Purpose (QH & NQH)						
Standard Tariff						
Tariff Components		**Price per Unit**	**Annual Price**	**Daily Price**	**Annual Quantity**	**Daily Quantity**
Standing Charge	per annum, pro-rated daily		€149.65	€0.4100		
SC Autoproducer	per annum, pro-rated daily		€77.38	€0.2120		
Unit Rate 1st Block	per kWh - first 47,815 kWh consumed annually, pro-rated daily	€0.1705			47,815	131
Unit Rate 2nd Block	per kWh - balance per period	€0.1625				
PSO (< 30 kVA)	per month end		€0.00			
PSO (>= 30 kVA)	per kVA - per month end		€0.00			

General Purpose (QH & NQH)						
Nightsaver Tariff						
Tariff Components		**Price per Unit**	**Annual Price**	**Daily Price**	**Annual Quantity**	**Daily Quantity**
Standing Charge	per annum, pro-rated daily		€160.60	€0.4400		
SC Autoproducer	per annum, pro-rated daily		€77.38	€0.2120		
Unit Rate Day 1st Block	per kWh - first 47,815 kWh consumed annually, pro-rated daily	€0.1736			47,815	131
Unit Rate Day 2nd Block	per kWh- balance per period	€0.1598				
Unit Rate Night	per kWh	€0.0695				
PSO (< 30 kVA)	per month end		€0.00			
PSO (>= 30 kVA)	per kVA - per month end		€0.00			

General Purpose (QH & NQH)				
Night Storage Heating				
Tariff Components		**Price per Unit**	**Annual Price**	**Daily Price**
Standing Charge	per annum, pro-rated daily		€8.03	€0.0220
Unit Rate	per kWh	€0.0695		

Residential Business Premises						
Standard Tariff						
Tariff Components		**Price per Unit**	**Annual Price**	**Daily Price**	**Annual Quantity**	**Daily Quantity**
Standing Charge	per annum, pro-rated daily		€120.45	€0.3300		
SC Autoproducer	per annum, pro-rated daily		€77.38	€0.2120		
Unit Rate 1st Block	per kWh - first 5,110 kWh consumed annually, pro-rated daily	€0.1435			5,110	14
Unit Rate 2nd Block	per kWh- balance per period	€0.1705				
PSO (< 30 kVA)	per month end		€0.00			
PSO (>= 30 kVA)	per kVA - per month end		€0.00			

Residential Business Premises						
Nightsaver Tariff						
Tariff Components		**Price per Unit**	**Annual Price**	**Daily Price**	**Annual Quantity**	**Daily Quantity**
Standing Charge	per annum, pro-rated daily		€149.65	€0.4100		
SC Autoproducer	per annum, pro-rated daily		€77.38	€0.2120		
Unit Rate Day 1st Block	per kWh - first 5,110 kWh consumed annually, pro-rated daily	€0.1435			5,110	14
Unit Rate Day 2nd Block	per kWh- balance per period	€0.1736				
Unit Rate Night	per kWh	€0.0695				
PSO (< 30 kVA)	per month end		€0.00			
PSO (>= 30 kVA)	per kVA - per month end		€0.00			

Residential Business Premises				
Night Storage Heating				
Tariff Components		**Price per Unit**	**Annual Price**	**Daily Price**
Standing Charge	per annum, pro-rated daily		€8.03	€0.0220
Unit Rate	per kWh	€0.0705		

Low Power Factor Surcharges (applicable to General Purpose and Residential Business Premises tariffs)		
Low Power Factor Surcharge applied to kVARh in excess of one third of kWh in any bill (For NQH metered customers, the billing period is two months. For QH metered customers, the billing period is one month)	0.00756	€/kVarh

Maximum Demand (Low Voltage) LVMD						
Tariff Components		Price per Unit	Annual / Seasonal* Price	Daily Price	Annual Quantity	Daily Quantity
Standing Charge	per annum, pro-rated daily		€1,025.65	€2.8100		
SC Autoproducer	per annum, pro-rated daily		€333.61	€0.9140		
Capacity Charge (MIC)	per kVA per annum, pro-rated daily		€25.55	€0.0700		
Excess Capacity NQH	per excess kVA per billing period	€12.78				
Excess Capacity QH	per excess kVA per billing period	€10.65				
MD (KW) - Summer*	pro-rated daily		€22.54	€0.0920		
MD (KW) - Winter*	pro-rated daily		€13.20	€0.1100		
Summer Unit Rate Day 1st Block	per kWh - first 2,099 kWh per kW of MD per annum - pro rated daily	€0.1457			2,099	5.75
Summer Unit Rate Day 2nd Block	per kWh - Balance per summer period	€0.1060				
Winter Unit Rate Day 1st Block	per kWh - first 2,099 kWh per kW of MD per annum - pro rated daily	€0.1680			2,099	5.75
Winter Unit Rate Day 2nd Block	per kWh - Balance per winter period	€0.1395				
Unit Rate Night	per kWh	€0.0680				
PSO (< 30 kVA)	per month end		€0.00			
PSO (>= 30 kVA)	per kVA - per month end		€0.00			

Low Voltage						
Low Voltage Low Load Factor Tariff						
Tariff Components		**Price per Unit**	**Annual Price**	**Daily Price**		
Standing Charge	per annum, pro-rated daily		€1,025.65	€2.8100		
SC Autoproducer	per annum, pro-rated daily		€333.61	€0.9140		
Capacity Charge (MIC)	per kVA per annum, pro-rated daily		€25.55	€0.0700		
Excess Capacity NQH	per excess kVA per billing period	€12.78				
Excess Capacity QH	per excess kVA per billing period	€10.65				
Summer Unit Rate Day	per kWh	€0.1595				
Winter Unit Rate Day	per kWh	€0.1867				
Unit Rate Night	per kWh	€0.0680				
PSO (< 30 kVA)	per month end		€0.00			
PSO (>= 30 kVA)	per kVA - per month end		€0.00			

Medium Voltage 10/20kV (Seasonal, Time of Day)				
MV STOD				
Tariff Components		**Price per Unit**	**Annual Price**	**Daily Price**
Standing Charge	per annum, pro-rated daily		€3,041.91	€8.3340
SC Autoproducer	per annum, pro-rated daily		€834.39	€2.2860
Capacity Charge (MIC)	per kVA per annum, pro-rated daily		€26.28	€0.0720
Excess Capacity QH	per excess kVA per billing period	€6.73		
Summer weekday - Day	per kWh	€0.1110		
Summer weekend - Day	per kWh	€0.0943		
Summer Night	per kWh	€0.0536		
Winter weekday - Day (excl peak)	per kWh	€0.1667		
Winter weekday - Day PEAK	per kWh	€0.2999		
Winter weekend - Day	per kWh	€0.1292		
Winter Night	per kWh	€0.0659		
PSO (< 30 kVA)	per month end		€0.00	
PSO (>= 30 kVA)	per kVA - per month end		€0.00	

38kv (Seasonal, Time of Day)				
38kv STOD				
Tariff Components		**Price per Unit**	**Annual Price**	**Daily Price**
Standing Charge - Looped	per annum, pro-rated daily		€40,798.97	€111.7780
SC Autoproducer - Looped	per annum, pro-rated daily		€3,801.11	€10.4140
Standing Charge - Tailed	per annum, pro-rated daily		€14,340.12	€39.2880
SC Autoproducer - Tailed	per annum, pro-rated daily		€3,800.75	€10.4130
Capacity Charge (MIC)	per kVA per annum, pro-rated daily		€21.17	€0.058
Excess Capacity QH	per excess kVA per billing period	€3.31		
Summer weekday - Day	per kWh	€0.1100		
Summer weekend - Day	per kWh	€0.0935		
Summer Night	per kWh	€0.0532		
Winter weekday - Day (excl peak)	per kWh	€0.1651		
Winter weekday - Day PEAK	per kWh	€0.2970		
Winter weekend - Day	per kWh	€0.1280		
Winter Night	per kWh	€0.0654		
PSO (< 30 kVA)	per month end		€0.00	
PSO (>= 30 kVA)	per kVA - per month end		€0.00	

110kV Transmission Connected (Seasonal, Time of Day)				
110kv STOD				
Tariff Components		**Price per Unit**	**Annual Price**	**Daily Price**
Standing Charge	per annum, pro-rated daily		€7,377.38	€20.2120
Capacity Charge (MIC)	per annum, pro-rated daily		€12.41	€0.0340
Summer weekday - Day	per kWh	€0.1066		
Summer weekend - Day	per kWh	€0.0906		
Summer Night	per kWh	€0.0515		
Winter weekday - Day (excl peak)	per kWh	€0.1601		
Winter weekday - Day PEAK	per kWh	€0.2881		
Winter weekend - Day	per kWh	€0.1241		
Winter Night	per kWh	€0.0633		
PSO (< 30 kVA)	per month end		€0.00	
PSO (>= 30 kVA)	per kVA - per month end		€0.00	

MIC Penalties (applicable to 110kV Tariff)	
A Networks Unauthorised Usage Charge per MWh applies to the 110 kV tariff for all energy at the 'defined' metering point (usually supply transformer 110kV bushings) used in excess of the customer’s Maximum Import Capacity.	€ 642 /MWh

Low Power Factor Surcharges (applicable to Low Voltage Maximum Demand, LV Low Load Factor, MV STOD & 38 kV STOD tariffs)		
Tariff		
Low Voltage Maximum Demand	0.00692	€/kVARh
Low Voltage Low Load Factor	0.00692	€/kVARh
Medium Voltage STOD	0.00609	€/kVARh
38 kV STOD	0.00567	€/kVARh
Low Power Factor Surcharge applied to kVARh in excess of one third of kWh in any bill (For NQH metered customers, the billing period is two months. For QH metered customers, the billing period is one month)		

Notes:

Summer Weekday
All weekdays in months March, April, May, June, July, August, September & October *excluding* Public Holidays.

Summer Weekend
All weekend days in months March, April, May, June, July, August, September & October *including* Public Holidays

Winter Weekday
All weekdays in months January, February, November & December *excluding* Public Holidays and the weekdays in the period 26th December to 31st December.

Winter Weekend
All weekend days in months January, February, November & December *including* Public Holidays and the weekdays in the period 26th December to 31st December.

Summer Weekday Hours: 08:00 to 23:00
Summer Weekend Hours: 08:00 to 23:00

Winter Weekday Hours: 08:00 to 17:00 and 19:00 to 23:00
Winter Weekday Peak: 17:00 to 19:00
Winter Weekend Hours: 08:00:00 to 23:00:00

Night Hours: 23:00 to 08:00.

Public Lighting				
Unmetered Supplies (urban/rural)				
Tariff Components		**Price per Unit**	**Annual Price**	**Daily Price**
Dusk to Midnight	per kWh	€0.2305		
Dusk to Dawn	per kWh	€0.1256		
24 hr supplies	per kWh	€0.1245		
PSO	per kVA - per month end		€0.00	

Public Lighting				
Metered Public Lighting *				
Tariff Components		**Price per Unit**	**Annual Price**	**Daily Price**
Standing Charge	per annum, pro-rated daily		€97.82	€0.2680
24 hr supplies	per kWh	€0.2305		
PSO	per kVA - per month end		€0.00	

* The "Metered Public Lighting (rural)" Tariff is a restricted tariff and will NOT apply to Public Lighting connections that become metered as a result of ESB Networks " >2kVA DUoS" rule, as detailed in paragraph 4.2.1 of "Rules for Application of Duos Tariff Group" (CER/04/300).

Unmetered				
Miscellaneous Unmetered Supplies				
Tariff Components		**Price per Unit**	**Annual Price**	**Daily Price**
Miscellaneous Unmetered	per kWh	€0.1905		
PSO	per kVA - per month end		€0.00	

Appendix 3

Rate Category	Standing Charge	MD	MIC/ MIC Excess	Flat Price/KWh **Seasonal Y/N**	Block 1 Price/KWh **Seasonal Y/N**	Block 2 Price/KWh **Seasonal Y/N**	Night Price/KWH 23:00 to 08:00 GMT **Seasonal Y/N**	Night Heating Standing Charge	Night Heating Price/KWh 23:00 to 08:00 GMT **Seasonal Y/N**	Low PF (KVARh)	PSO
Residential: Domestic Urban 24 Hr.	✓			✓ **N**			No	✓	✓ **N**		✓
Domestic Urban Nightsaver	✓			✓ **N**			✓ **N**	✓	✓ **N**		✓
Domestic Rural 24 Hr	✓			✓ **N**			No	✓	✓ **N**		✓
Domestic Rural Nightsaver	✓			✓ **N**			✓ **N**	✓	✓ **N**		✓
Residential Business 24 Hr.	✓				✓ **N**	✓ **N**		✓	✓ **N**	✓	✓
Residential Business Nightsaver	✓				✓ **N**	✓ **N**	✓ **N**	✓	✓ **N**	✓	✓
Commercial/Industrial: General Purpose 24 Hr.	✓				✓ **N**	✓ **N**		✓	✓ **N**	✓	✓
General Purpose Nightsaver	✓				✓ **N**	✓ **N**	✓ **N**	✓	✓ **N**	✓	✓
Low Load Factor	✓		✓	✓ **Y**			✓ **N**			✓	✓
Low Voltage MD	✓	✓	✓	✓ **Y**	✓ **Y**	✓ **Y**	✓ **N**			✓	✓
Public Lighting: Metered (Restricted to existing 30 customers)	✓			✓ **N**							✓
Public Lighting Unmetered – Dusk to Dawn, Dusk to Midnight, 24 Hours.				✓ **N**							✓
Unmetered Single Point				✓ **N**							✓
LEUs: MV – SToD*	✓		✓	✓ **Y**			✓ **Y**			✓	✓
38KV – SToD*	✓		✓	✓ **Y**			✓ **Y**			✓	✓

110 KV – SToD.*	✓		✓ No Excess	✓ **Y**			✓ **Y**				✓

Season Time of Day (SToD) periods[6]:

Time of Day	Summer Monday to Friday 08:00 to 23:00	Summer Saturday/Sunday 08:00 to 23:00	Summer Nightly 23::00 to 08:00	Winter Monday to Friday 08:00 to 23:00	Winter Saturday/Sunday 08:00 to 23:00	Winter Nightly 23::00 to 08:00
Weekday	✓			✓		
Weekday Peak				✓ (17:00 to 19:00)		
Weekend		✓			✓	
Night			✓			✓

[6] In the STOD format, Public Holidays are treated as “weekends” even if they fall on a weekday.

Appendix 4

Retail Tariff Categories mapped to DUoS & TUoS categories

ESBNetworks	EIRGRID	ESBCS
DUoS Group (DG)	Demand Transmission Service (DTS)	Rate Category (Tariff)
DG1	DTS-D2	Domestic Urban – 24 Hr. Domestic Urban – Nightsaver (NS)
DG2	DTS-D2	Domestic Rural – 24 Hr. Domestic Rural – NS.
DG3	DTS-D2	Public Lighting – Unmetered Unmetered Single Point Connections
DG4 -Unused		Unused
DG5	DTS –D1(=>500KVA) DTS-D2	General Purpose Commercial – 24 Hr. General Purpose Commercial – NS. General Purpose Industrial – 24 Hr. General Purpose Industrial – NS Residential Business (Restricted Tariff) – 24 Hr. Residential Business (Restricted Tariff) – NS. Metered Public Lighting (Restricted Tariff).
DG6	DTS –D1(=>500KVA) DTS-D2	LV Maximum Demand Commercial. LV Maximum Demand Industrial. LV Low Load Factor.
DG7	DTS –D1(=>500KVA) DTS-D2	MV Seasonal Time of Day (SToD)
DG8	DTS –D1(=>500KVA) DTS-D2	38 KV Looped SToD
DG9	DTS –D1(=>500KVA) DTS-D2	38 KV Tailed SToD
DG10	DTS –D1(=>500KVA) DTS-D2	110 KV SToD – Distribution Connected
TCON	DTS-T	110 KV SToD – Transmission Connected