Price List Information

ELECTRICITY NETWORKS CORPORATION

("WESTERN POWER")

ABN 18 540 492 861

{Outline: This price list information is included in Western Power's access arrangement in accordance with section 5.1 of the Code.}

Table of contents

1 Introduction

This document is Western Power’s Price List Information, as defined in the Electricity Networks Access Code 2004 (the Code).

This document details:

- The history of the network tariffs;
- The objectives and principles that underlie Western Power’s approach to deriving the reference tariffs; and
- The methodology of deriving cost of supply and the reference tariffs from the target revenue.

1.1 Code Requirements

Section 8.1 of the Code requires Western Power to submit Price List Information to the Authority.

The Code defines Price List Information as:

> “price list information” means a document which sets out information which would reasonably be required to enable the Authority, users and applicants to:
>
> (a) understand how the service provider derived the elements of the proposed price list; and
>
> (b) assess the compliance of the proposed price list with the access arrangement.

1.2 Foreword

This document is the Price List Information for the Price List that will apply from the revisions commencement date until 30 June 2010.

This document sets out the principles that are embedded in the tariffs by virtue of the tariff rebalance in 2006/07. In setting the tariffs, consistent with the revenue path across this access arrangement period, the tariffs have been uniformly inflated rather than rebalanced. In the future Western Power will apply the principles detailed in this document to achieve more cost reflective tariffs.

1.2.1 Scaled increase

The prices have increased on average by 16.3% when compared to the current price list. It is expected that the 2010/11 and the 2011/12 prices will be similarly set by a uniform inflator adjustment. The tariff increases are required to ensure that Western Power recovers the approved revenue cap for reference services.

Section 9 details the % change in all tariff components when compared to the 2009/10 price list.

1.2.2 Forecast revenue recovery

The following table sets out the reference service revenue, by tariff, that is forecast to be collected when applying this Price List from the revisions commencement date (assumed to be 1 March 2010) until 30 June 2010.

Table 1 - Revenue Forecast – 1 March – 30 June 2010 ($M Nominal)

	kWh	Number Customers	Forecast Transmission Revenue Recovered	Forecast Distribution Revenue Recovered
TRT1 – Transmission Exit	N/A	27	7.5	0.0
TRT2 – Transmission Entry (includes LV Gens etc.)	N/A	26	17.5	0.0
RT1 - Anytime Energy (Residential)	1,610,437,212	784,424	24.7	100.4
RT2 - Anytime Energy (Business)	535,655,111	87,969	9.9	34.9
RT3 - Time of Use Energy (Residential)	84,131,327	15,903	1.3	4.1
RT4 - Time of Use Energy (Business)	689,281,992	11,997	10.1	24.4
RT5 - High Voltage Metered Demand	96,955,034	113	1.5	2.1
RT6 - Low Voltage Metered Demand	358,122,635	1,038	5.4	8.9
RT7 - High Voltage Contract Maximum Demand	916,637,795	226	15.3	8.5
RT8 - Low Voltage Contract Maximum Demand	88,879,102	50	1.4	1.6
RT9 – Streetlighting	35,821,386	217,642	0.4	6.4
RT10 - Un-Metered Supplies	11,255,505	15,266	0.1	0.7
RT11 - Distribution Entry	0	13	0.0	0.1
RT12 - Time of Use Energy (Bidirectional Residential)	10,099,641	7,007	0.2	0.9
TOTAL	**4,437,276,739**	**1,141,701**	**95.3**	**192.9**
Over/(Under) recovery compared to reference service revenue allocated to 1 March 2010 – 30 June 2010			**(0.3)**	**2.5**

Western Power considers that the differences between required and forecast revenues from reference services are within a reasonable margin when determining a complex set of reference tariffs. Western Power also notes that, under the price control of the access arrangement, any differences between required and actual revenues will be corrected for in transmission and distribution prices in future pricing years.

1.2.3 Introduction of the RT12 tariff

This Price List details the RT12 tariff for the first time. RT12 is the tariff associated with the C1 – Time of Use (Residential) Bidirectional Service.

In setting the prices for various components of the RT12 tariff Western Power has applied the following principles:

- The prices for the various components must be comparable with the prices for the RT1 & RT3 tariff components given these tariffs are also payable by residential customers and have been uniformly inflated in this Price List;
- The prices for on-peak components must take into account the shorter on-peak period when compared to the RT3 tariff; and

- The average tariff payable by users on the RT12 tariff must be comparable with the average tariff payable by users of the RT1 tariff.

To achieve these principles Western Power has:

- Set the fixed use of system charge to be identical to RT1 & RT3;
- Set the off peak use of system charge to be identical to the off peak use of system charge for RT3 given that the off peak periods are largely identical;
- Set the shoulder use of system charge to be identical to the variable use of system charge for RT1;
- Set the on peak use of system charge to be marginally higher that the on-peak use of system charge for RT3 to reflect the more concentrated on-peak period, to provide a signal to users to shift their consumption to other times and to ensure that the average tariff payable is comparable with RT1; and
- Set the metering charges to be identical to the metering charges for RT3 given that the metering capabilities required for users with RT12 is very similar to users of RT3.

1.2.4 Note on the tables in this document

This price list is unusual as it is expected to apply for a period of four months. Western Power's transmission and distribution cost of supply (COS) models calculate costs and revenue assuming the price list operates for a full year. To cater for this Western Power has annualised the maximum regulated revenue to produce the graphs and table presented in sections 4 - 8.

1.3 History of the Tariffs

Prior to the commencement of the Access Code 2004 and the first Access Arrangement Western Power had in place a suite of tariffs to recover the regulated revenue for both the transmission and distribution network businesses.

Network tariffs have been in place since the introduction of de-regulation into the south-west electricity network in 1996. Initially tariffs were only determined and published for contestable users but from July 2001 network tariffs were established for all users whether contestable or franchise.

In July 2001 the network tariff structure changed somewhat from the structure in place before 2001. This became necessary to improve the efficiency of the tariff structure and to cater, in particular, for the smaller contestable, and non-contestable users. Prior to 2001 the transmission and distribution access price structures were entirely different and users seeking access to the networks had separate transmission and distribution access contracts and paid separate charges.

Once the principle was established that access prices were required for all users and all users were to be charged for access, it became imperative to develop appropriate tariffs. This was achieved by a full review of the tariff structures and making the transmission and distribution tariff structures compatible, so that for distribution–connected users the tariffs could be added together at a component level to form a bundled tariff. The transmission and distribution tariffs settings were still separately determined through a transparent process.

Users that were contestable prior to July 2001 were given the option of remaining on the previous tariffs or migrating to the new tariffs. This was facilitated by the retention of a set of transition tariffs. Western Power ceased to offer transition tariffs on 30 June 2009.

Western Power has retained the network tariff structure for the reference services offered under the Access Arrangement. It is the derivation of these reference tariffs to which the remainder of this document is dedicated.

2 Pricing Principles

This section discusses the principles, objectives and an overview of the methodology used in determining the reference tariffs.

2.1 Pricing Objectives

Reference service revenue is recovered through a set of reference tariffs that have been designed to meet high-level objectives described below.

Note: Transmission and distribution are treated separately and each has independent target revenue for reference services.

The reference service revenue is recovered from users in a manner that is:

- Economically efficient;
- Transparent;
- Practical; and
- Equitable.

In addition to these objectives, the pricing methodology is developed to:

- Achieve the reference service revenue to maintain a viable network business and to deliver efficient network services to all network users;
- Be as cost reflective as is reasonable to reflect the network user's utilisation of the network including use of dedicated assets;
- Promote efficient use of the network through appropriate price signalling;
- Maintain price stability and certainty to enable network users to make informed investment decisions;
- Be as simple and straightforward as is reasonable taking into account other objectives; and
- Avoid cross subsidy between different user groups. From an economic efficiency perspective this requires that the reference tariff be between the incremental cost of supply and the stand-alone cost of supply.

2.2 Pricing Principles

Western Power has adopted the following principles that are designed to meet the pricing objectives set out in the previous section.

1. Reference tariffs are to be designed to recover the reference service revenue entitlement while meeting any side constraints to prevent price shock to users.

2. The prices will be based on a well-defined and transparent methodology.

3. The prices will be based on analysis of the cost of supply provision that includes:

   a. Definition of the classes of service provided,

   b. Allocation of fixed and variable network costs to service classes, and

   c. Price setting to recover the fixed and variable costs.

4. Prices will signal the economic cost of supply provision in that they will:

   a. Avoid cross subsidies between classes of service, and

   b. Avoid cross subsidies between customers within each class of service.

5. Provided that economic costs are covered, prices will be responsive to user requirements in order to

   a. Avoid economic bypass, and

   b. Allow for negotiation where provided within the Code.

6. Provide economic signals to encourage efficient use of the network.

7. Reference tariffs for users with annual energy demand below 1 MVA are uniform (consistent with the section 7.7 of the Code), but will meet the pricing principles described above, as far as is practical.

2.3 Pricing Methods

The pricing methods (cost allocations) are set out in section 9.4 of the Access Arrangement as follows:

Overview of Pricing Method

9.4 *Reference tariffs* are derived from an analysis of the cost of service provision which entails:

(a) identifying the costs of providing *reference services*;

(b) allocating the costs of providing *reference services* to particular customer groups;

(c) translating the costs of serving particular customer groups to the costs of providing *reference tariffs*; and

(d) determining a structure of *reference tariffs* in a manner that reflects the underlying cost structure, in accordance with section 7.6 of the Code.

This section provides a summary of Western Power's pricing methods. Further detail is provided in the remainder of this document.

2.3.1 General

Reference tariffs aim to reasonably reflect the cost of providing the network service to users. The first step in developing reference tariffs is to model the cost of supply for users. The cost of supply cannot be derived at an individual user level and so users are categorised into a number of groups with similar costs.

Reference tariffs will generally have a number of components, which fall into fixed and variable categories. Fixed components would generally be a charge per user regardless of their size whereas the variable component would be related to energy or demand. These categories of costs reflect the fact that costs will be related either to the number of users serviced or to the amount of capacity provided.

It is essential to separate the two processes of "determining cost of supply" and "setting reference tariffs" to recover those costs. In the ideal world the costs of supply can be clearly allocated to particular customer groups and the reference tariffs are set to exactly recover those costs. In addition, the costs are separated into fixed and variable components and the reference tariffs are similarly split so that fixed costs are recovered by fixed charges and variable costs by variable charges.

It is recognised that the determination of the cost of supply for users and respective reference tariffs is an inexact process. A number of simplifying assumptions are required, for example, to categorise users into a small number of customer groups or classes with similar characteristics. These assumptions may introduce a degree of imprecision in tariff setting, but this is not considered to be significant and there is considerable historical precedence in deriving the network cost of supply that supports the approach.

It is also noted that demand is the best measurement of capacity. However, the vast majority of users have energy only metering that does not record demand, and therefore energy is used as a proxy for demand. The limitations on the metering information available will also introduce a degree of imprecision that cannot be avoided or readily quantified.

2.3.2 Process to Determine Cost of Supply

This section presents an overview of the process to derive the cost of supply. Detailed information on this process is provided in sections 4 and 5.

There are two basic stages in determining the cost of supply for users:

- Determination of the reference service revenue for Western Power; and
- Allocation of the revenue components to different cost pools for various customer groups, based on factors such as supply voltage, location and load characteristics.

Determination of the reference service revenue requirement for Western Power is detailed in section 3 and is undertaken in accordance with the Access Arrangement.

Note: Transmission and distribution are treated separately and each has independent target revenues.

The reference service revenue requirement must then be allocated to asset classes and the use of the assets allocated to users.

The customer groups used in the analysis and modelling of costs generally reflect the nature of the physical connection to the network and the relative size and nature of the user, namely:

Transmission connected:

- Transmission Generation
- Transmission Loads

Distribution connected:

- High Voltage >1MVA maximum demand
- High Voltage <1MVA maximum demand
- Low Voltage >1MVA maximum demand
- General Business Large (300-1,000 kVA maximum demand)
- General Business Medium (100-300 kVA maximum demand)
- General Business Small (15-100 kVA maximum demand)
- Small Business (<15 kVA maximum demand)
- Residential
- Streetlights
- Unmetered Supplies

2.3.3 Process to Determine Reference Tariffs

This section presents an overview of the process by which reference tariffs are derived. Detailed information on the process is provided in sections 7 and 8.

Reference tariffs are derived from the cost of supply determination. The reference tariffs do not directly relate to the customer groups. This is because a number of the customer groups are based on derived user demands whereas the reference tariffs are based on the user and metering data that is actually available.

The users within the customer groups are linked to reference tariffs so that cost of supply can then be derived for each reference tariff. The cost of supply is in terms of fixed and variable costs and price settings are then simply established to recover the cost pools from the users.

2.3.4 Modelling Cost Allocations

Western Power’s transmission and distribution cost of supply (COS) models accurately reflect the network cost of supply for the various customer groups. The model assembles capital and operating costs for the components (lines, substations, transformers, etc.) of the modern equivalent assets employed in providing network capacity and delivering energy and allocates these to each customer group according to a pre-determined set of principles.

Tables from Western Power's COS model are provided in this document to demonstrate that Western Power complies with its cost allocation methodology.

3 Derivation of Maximum Regulated Revenue

This section details the derivation of the transmission and distribution maximum regulated revenue based on the 2009/10 revenue allowance that is allocated in the Revenue Model to the final four months of the 2009/10 financial year.

3.1 Maximum Transmission Regulated Revenue

For the purposes of this Price List Information the revenue used to derive the transmission system cost of supply cost pools is based on the revenue allowed for in the last four months of the financial year, which is then annualised. The derivation is demonstrated in the following tables.

Table 2 sets out the total revenue requirement for the 2009/10 financial year as defined in the Access Arrangement. The total revenue requirement is allocated between the first eight months of the year and the final four months in accordance with the Revenue Model.

Table 2 - Transmission Reference Service Revenue ($M Real as at 30 June 2009)

	Revenue 1 Jul 09 – 28 Feb 10	Revenue 1 Mar 10 – 30 Jun 10	Revenue $TR_{2009/10}$
Reference Service Revenue	168.1	94.8	262.9

Western Power’s transmission and distribution cost of supply (COS) models require annual equivalent cost inputs. Table 3 details the equivalent annual transmission revenue by prorating the revenue entitlement for 1 March 2010 to 30 June 2010 over 12 months.

Table 3 – Annualised Equivalent Transmission Reference Service Revenue (based on 1 March to 30 June 2010 revenue) ($M)

	Revenue (Real)	Revenue (Nominal)
Reference Service Revenue$_{\text{March – June 2010}}$	94.8[1]	95.6
Annualised Reference Service Revenue$_{2009/10}$	284.5	**286.8**

3.2 Maximum Distribution Regulated Revenue

For the purposes of this Price List the revenue used to derive the distribution system cost of supply cost pools is based on the revenue allowed for in the last four months of the financial year, which is then annualised. The derivation is demonstrated in the following table.

Table 4 sets out the total revenue requirement for the 2009/10 financial year as defined in the Access Arrangement. The total revenue requirement is allocated between the first eight months of the year and the final four months in accordance with the Revenue Model.

Table 4 - Distribution Reference Service Revenue ($M Real as at 30 June 2009)

	Revenue 1 Jul 09 – 28 Feb 10	Revenue 1 Mar 10 – 30 Jun 10	Revenue $DR_{2009/10}+TEC$
Reference Service Revenue	321.2	188.9	510.1

[1] Source: Western Power Revenue Model, Transmission_CoS Sheet

Western Power's transmission and distribution cost of supply (COS) models require annual equivalent cost inputs. Table 5 details the equivalent annual distribution revenue by prorating the revenue entitlement for 1 March 2010 to 30 June 2010 over 12 months.

Table 5 – Annualised Equivalent Distribution Reference Service Revenue (based on 1 March to 30 June 2010 revenue) ($M)

	Revenue (Real)	Revenue (Nominal)
Reference Service Revenue$_{\text{March – June 2010}}$	188.9[2]	190.5
Annualised Reference Service Revenue$_{\mathbf{2009/10}}$	566.8	**571.4**

3.3 Derivation of Inflation Factor

In sections 3.1 and 3.2 Western Power has inflated the reference service revenue from real terms to nominal terms by using the relevant published March quarter CPI data (refer sections 5.35 and 5.46 of the Access Arrangement), where available, and to use forecast inflation[3] in accordance with the revenue model in all other instances.

Table 6 - Derivation of 2009/10 Inflation Factor

March 2009 – March 2010 – Forecast	0.8%
Derived Inflation Factor	1.008

[2] Source: Western Power Revenue Model, Distribution_CoS Sheet

[3] The CPI forecast in the revenue model is a June to June CPI forecast

4 Derivation of Transmission System Cost of Supply

This section details the derivation of the transmission system cost of supply for connection points on the transmission system.

4.1 Cost Pools

The following cost pools are used in the derivation of the transmission system cost of supply:

- Connection Services Cost Pool:
  which is further allocated to the following cost pools:
  - Connection Services for Exit Points Cost Pool; and
  - Connection Services for Entry Points Cost Pool.
- Shared Network Services Cost Pool:
  which is further allocated to the following cost pools:
  - Use Of System for Loads Cost Pool;
  - Use Of System for Generators Cost Pool; and
  - Common Service for Loads Cost Pool.
- Control System Services Cost Pool:
  which is further allocated to the following cost pools:
  - Control System Services for Loads Cost Pool; and
  - Control System Services for Generators Cost Pool.

4.1.1 Connection Services for Exit Points Cost Pool

The Connection Services for Exit Points Cost Pool includes the GODV (Gross Optimised Deprival Value) of all connection assets at each Exit Point and one-third of the value of the voltage control assets at those points (since the function of voltage control equipment is partly location specific and partly system related).

4.1.2 Connection Services for Entry Points Cost Pool

The Connection Services for Entry Points Cost Pool includes the GODV of all connection assets at each Entry Point and one-third of the value of the voltage control assets at those points (since the function of voltage control equipment is partly location specific and partly system related).

4.1.3 Use of System for Loads Cost Pool

Use Of System for Exit Points Cost Pool includes 50% of the total Shared Network Services Cost Pool.

4.1.4 Use of System for Generators Cost Pool

Use Of System for Entry Points Cost Pool includes 20% of the total Shared Network Services Cost Pool.

4.1.5 Common Service for Loads Cost Pool

The Common Service for Loads Cost Pool includes:

- 30% of the total Shared Network Services Cost Pool.
- Shared Voltage Control Assets – two thirds of the value of voltage control assets at Entry and Exit points (since the function of voltage control equipment is partly location specific and partly system related) and the value of all of voltage control assets at transmission substations. NB The remaining one-third of the value of the voltage control equipment at Entry and Exit points is included in the Connection Services Cost Pool (see above).
- Generation Support Charge - is an annual pass through cost determined by the market operator for running some small generation units out of merit in order to minimise excessive transmission losses and aid in system stability.
- Regulation Service to Loads - is an annual pass through cost determined by the market operator required to control frequency variations caused by load fluctuations (see Western Power Networks, 'Price Publication – Part E').
- Adjustments for any under or over recovery in revenue from previous financial years, or any under recovery expected due to price caps in the current year.

4.1.6 Control System Service for Loads Cost Pool

The Control System Service for Loads Cost Pool consists of a portion of the total cost of all SCADA, SCADA related communications equipment, and costs associated with the control centre, proportioned based on the total number of points in the SCADA master station relevant to loads.

4.1.7 Control System Service for Generators Cost Pool

The Control System Service for Generators Cost Pool consists of a portion of the total cost of all SCADA, SCADA related communications equipment, and costs associated with the control centre, proportioned based on the total number of points in the SCADA master station relevant to generators.

4.2 Cost of Supply

In order to calculate transmission cost of supply, all transmission assets are valued and categorised into the above cost pools. Each network branch is further defined as either exit, entry or shared network and cost allocation is then applied based on the GODV (Gross Optimised Deprival Value) of all relevant assets.

4.2.1 Transmission Assets

The principal elements of the transmission networks include transmission substations and zone substations, interconnected by transmission and sub-transmission lines. The transmission networks enable the transportation of electricity from power stations to zone substations and high voltage user loads. The zone substations provide the interface between the transmission networks and distribution networks.

Generally, the transmission networks assets comprise connection assets, shared Network assets and other or ancillary assets. These are described as follows:

- Connection Assets: those assets at the point of physical interconnection with the transmission networks which are dedicated to a User - that is, at substations including transformers and switchgear, but excluding the incoming line switchgear. Connection assets for generators are referred to as entry assets and for loads they are called exit assets.

- Shared Network Assets: all other transmission assets, which are shared to some extent by network Users.
- Other or Ancillary Assets: network assets performing an Ancillary Services function comprise:
    - those providing a Control System Service, for example, system control centres, supervisory control and communications facilities.
    - those providing a Voltage Control Service in the networks, for example, a proportion of the costs of capacitor and reactor banks in substations.

Figure 1 shows in simplified form the principal elements of the transmission networks and the categorisation of the assets as described above.

Transmission Network Assets

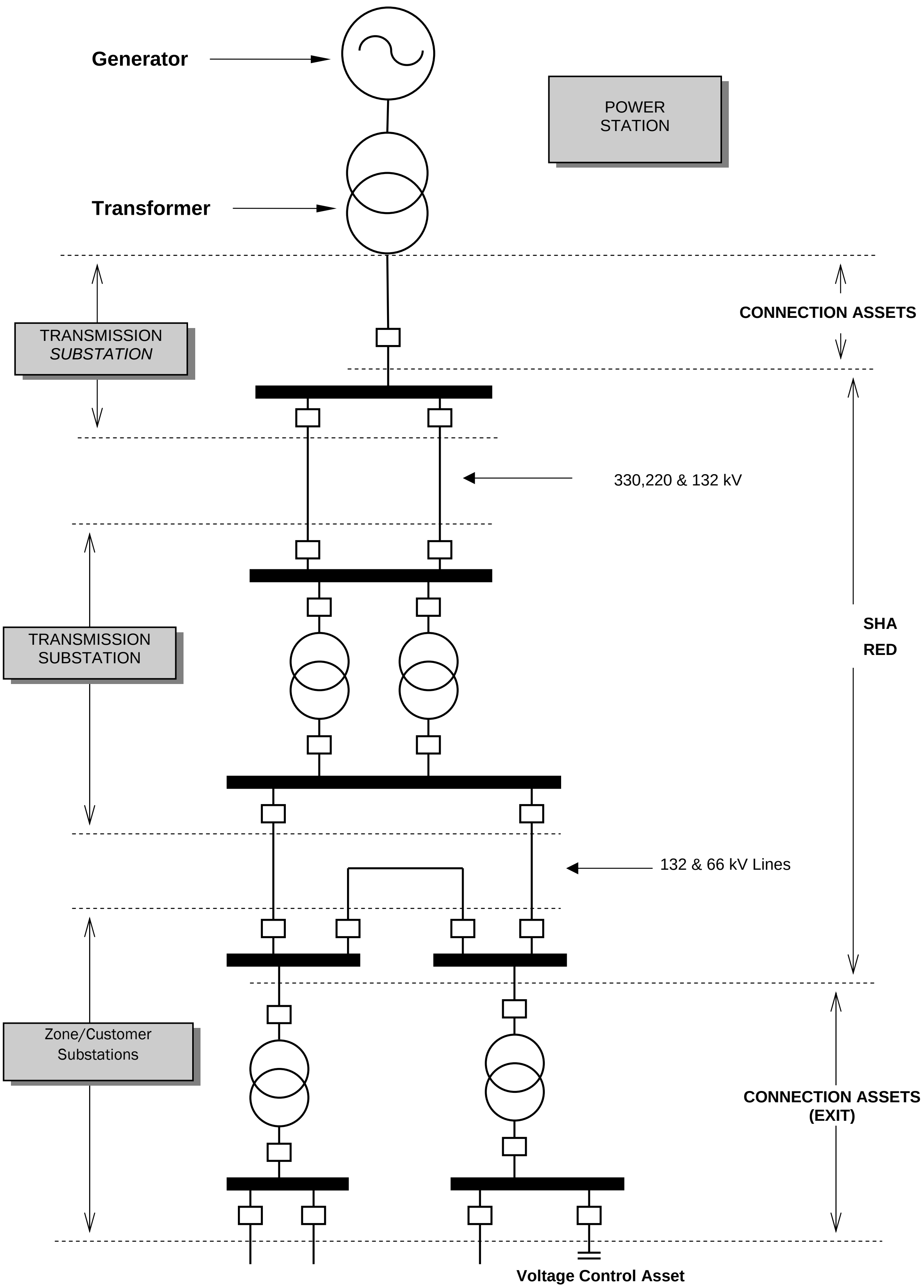

Figure 1 - Transmission Network Assets

4.2.2 Asset Valuation

All valuations of transmission assets are performed using the Optimised Deprival Value (ODV) methodology.

4.2.3 Valuation of Individual Branches and Nodes

To determine cost of supply, valuation data is required for every individual branch and node on the network. Every branch and node consists of many individual asset valuation building blocks that are all individually assessed.

Branches include transmission lines and transformers and include the substation circuits at each end. Each transmission line branch will typically have the cost of each of the circuit breakers at different substations included, whereas each transformer branch will typically have the cost of each of the circuit breakers at that same substation included.

Substation site establishment costs are allocated equally to all substation circuits.

The costs for shared circuit breakers (such as bus section breakers etc.) are allocated equally between all other substation circuits, which derive benefit from that shared circuit breaker.

4.3 Methodology of Allocating to Cost Pools

4.3.1 Overview

The methodology for allocating the transmission revenue to each cost pool is to allocate the revenue in the proportion to the GODV of the assets in each cost pool.

However, the Annual Revenue Requirement for the Control System Service Cost Pool is calculated separately (using the same method as for all other network assets) but assuming higher depreciation and operating expenditure than for other network assets. When calculating other Cost Pool Revenues appropriate adjustments are required.

Consequently:

Cost Pool Revenue = RR * GODV (Cost Pool)

where:

RR = a revenue rate of return (RR) determined as $AARR_{network} / \Sigma GODV_{network}$

$AARR_{network}$ = Transmission Reference Service Revenue excluding Annual Revenue Requirement for Control System Services.

GODV (Cost Pool) = GODV of the transmission network assets which belong in that cost pool.

$\Sigma GODV_{network}$ = GODV of all transmission assets excluding Control System Service assets.

4.4 Cost Pool Allocations

Applying the above methodology, the following cost pool revenues were derived (before applying pricing side constraints) for 2009/10:

Table 7 - Transmission Pricing Cost Pools for 1 March to 30 June 2010 ($M Nominal Annualised)

Cost Pool	Allocated Revenue
Entry Connection	5.9
Exit Connection HV	0.5
Exit Connection LV	77.4
Control System Services for Generators	3.1
Control System Services for Loads	18.4
Use Of System for Generators	42.2
Use Of System for Loads	99.4
Common Service for Loads (including Voltage Control)	40.0
Metering CT/VT	0.4
Standby	-0.5
Total	**286.8**

Note: The standby cost pool relates to Western Power providing standby services. This cost pool has been removed from the costs associated with reference services due to the standby service being provided as a non-reference service.

5 Derivation of Distribution System Cost of Supply

This section details the derivation of the distribution system cost of supply for connection points on the distribution system.

The derivation of the Distribution System Cost of Supply operates along the same principles as the transmission system. That is, the reference service revenue entitlement (which includes the tariff equalisation contribution (TEC)) is determined for the distribution system, and that revenue is then allocated to asset categories to derive the cost of supply for each of the customer groups. The cost of supply is based on the relative usage of each asset category by the various customer groups.

The structure of the distribution network cost of supply and reference tariffs reflects the features of the distribution network.

5.1 Cost Pools

The distribution cost pools used in the Distribution System Cost of Supply are:

- High Voltage Network
- Low Voltage Network
- Transformers
- Streetlight Assets
- Metering
- Administration

5.2 Customer Groups

The distribution customer groups used in the Distribution System Cost of Supply are:

- High Voltage >1MVA maximum demand
- High Voltage <1MVA maximum demand
- Low Voltage >1MVA maximum demand
- General Business Large (300-1,000 kVA maximum demand)
- General Business Medium (100-300 kVA maximum demand)
- General Business Small (15-100 kVA maximum demand)
- Small Business (<15 kVA maximum demand)
- Residential
- Streetlights
- Unmetered Supplies

5.3 Locational Zones

Distribution reference tariffs are provided for individual locational zones for users with energy demands in excess of 1 MVA. Locational zones are defined as those areas supplied by the network where the distribution system cost of supply is similar. For example, the rural wheat belt areas of Western Australia are considered to have a reasonably uniform distribution system and costs of supply, as do the urban and CBD areas of Perth.

Zone substations with similar cost structures are allocated to locational zones that feed an area of the distribution system. Where a zone substation supplies an area of more than one distinct cost of supply, then all users supplied from that substation are considered to be in the one dominant category. That is, there is only one locational zone defined for each zone substation.

The five zones are defined in the sections below, and for details of the allocation of each zone substation to locational zones see the Price List in the Access Arrangement.

5.3.1 CBD Locational Zone

This is defined as the intense business area generally recognised as the Perth CBD area. The defining street boundaries is generally from the Swan River north to Aberdeen Street Northbridge, west to Rokeby Road Subiaco, and east to the East Perth redevelopment area.

5.3.2 Urban Locational Zone

This is defined as the uniformly and continuously settled areas of Perth that contains the urban domestic, commercial and industrial users but exclude the CBD. This area also excludes the outer urban area that is treated as mixed. The country towns of Geraldton and Kalgoorlie are also included.

5.3.3 Rural Locational Zone

This is defined to include those areas which have a predominantly rural/farming characteristic and includes small to medium size towns within the southwest land division, eg, Merredin.

5.3.4 Mixed Locational Zone

This is defined to include those areas that have a mixed user base that has at least two dominant load types. For example, a mix of significant mining and rural loads or significant urban and rural loads. It also includes significant outer areas of Perth, which can be a mix of fringe urban, semi-rural and rural types, eg, Yanchep.

5.3.5 Mining Locational Zone

This is defined to include the mining area surrounding Kalgoorlie, which is supplied at 33 kV and the mining area at Forrestania which is also supplied at 33 kV. It does not include the town of Kalgoorlie.

5.4 Methodology of Deriving the Cost of Supply

5.4.1 Flowchart

The derivation of the cost of supply for each customer group the process followed is illustrated in the following flow diagram.

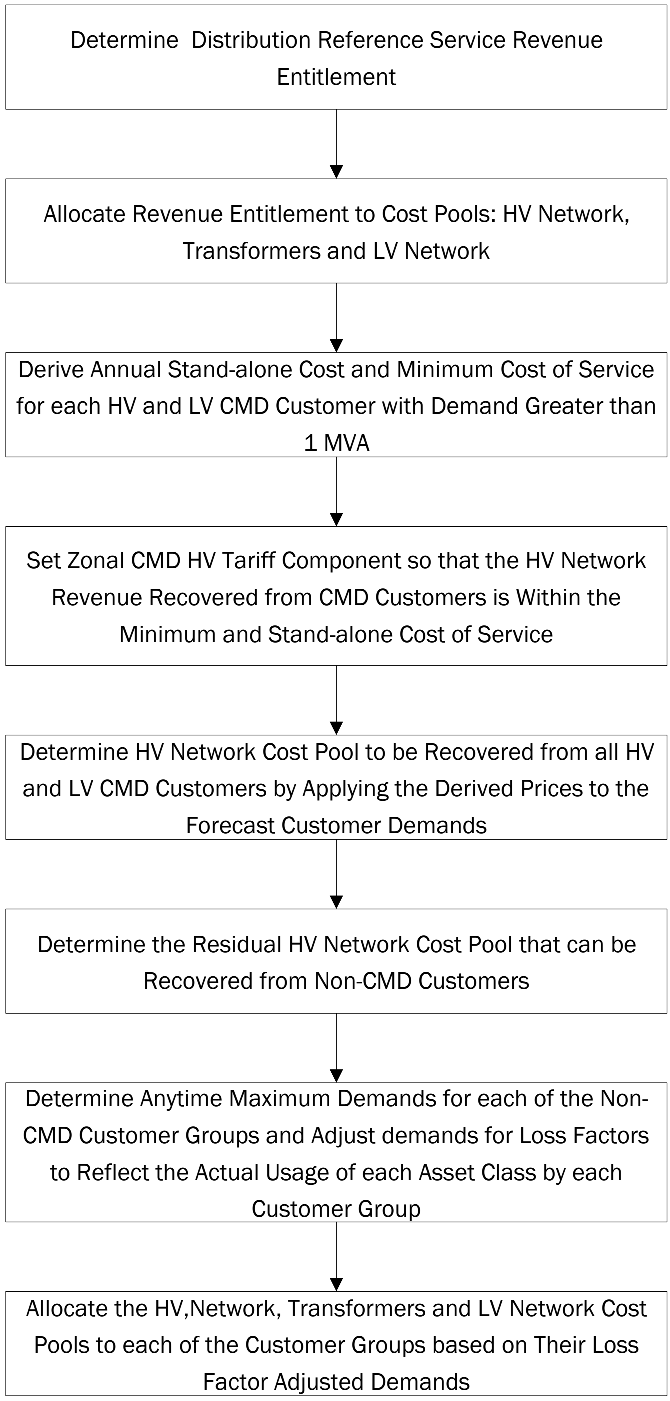

Figure 2 - Distribution Cost of Supply Flow Chart

Each step in this process to derive the distribution cost of supply is described in more detail as follows.

5.4.2 Calculate the Forecast Distribution Network Revenue to be Recovered from Distribution-Connected Users

It is assumed at this stage that the forecast distribution network revenue entitlement has been determined in accordance with the approach approved by the ERA in the Access Arrangement.

The forecast distribution network revenue entitlement includes an amount for the tariff equalisation contribution (TEC). The allocation of TEC to the cost pools and the customer groups is undertaken on the same basis as the network revenue entitlement set out below.

5.4.3 Allocate Revenue Entitlement to Cost Pools HV Network, Transformers and LV Network

The network revenue entitlement is then allocated to each of the asset classes being the HV network, transformers and the LV network. The allocation is based on the gross ODV of each asset category as a proportion of the total gross ODV.

5.4.4 Derive HV Annual Stand-alone Cost and Incremental Cost of Supply for each HV and LV CMD Users with Demand Greater than 1 MVA

In the cost of supply analysis, the costs for users with annual maximum demands less than 1,000 kVA are assumed to be uniform across the network whereas costs for users with demands above 1,000 kVA are determined on the basis of their being affected by their location on the network and their relative use of network assets.

On this basis, the HV network costs that can be allocated to users with maximum demands in excess of 1,000 kVA are calculated through a process that ensures that the cost is between the incremental cost of supply and the stand-alone cost. This approach is consistent with the requirements of section 7.3 of the Code and demonstrated within the Access Arrangement.

In terms of costs of supply analysis, this approach is contrary to the approach for users with demands below 1,000 kVA. For these users the approach is facilitated by allocating the network costs on the basis of sharing the average costs of the network between users depending on their relative usage of the network components.

This approach for larger users can distort the final price outcomes because it assumes that costs can be allocated linearly on usage. This approach is reasonable for smaller users where the stand-alone cost will far exceed the average cost of supply. On the other hand, the stand-alone cost for larger users can be less than a simple linear allocation of costs and for this reason it is essential to take a different approach.

The approach taken is to derive the HV network incremental and standalone cost for each user with maximum demand in excess of 1,000 kVA. This process will give maximum and minimum revenues that could be recovered from this customer group.

The reality of network pricing is that the actual revenue recovered from these users should fall between these two values. The actual value is determined by deriving reference tariff components that, when applied to the forecast user data will produce charge and revenue outcomes that recover at least the incremental cost of supply but do not recover more than the standalone cost of supply. The detail of this price setting is contained in section 8.

5.4.5 Redefine Revenue Pools

The outcome of the process to date is that the HV network revenue for HV and LV users with maximum demands greater than 1,000 kVA has been forecast. This now results in a reallocation of the reference tariff revenue entitlement into the costs pools of:

- HV network cost pool that is recovered from users with demands greater than 1,000 kVA.
- Residual HV network cost pool for users with demands less than 1,000 kVA,

- Transformer cost pool, and
- LV network cost pool.

These cost pools must now be allocated to customer groups based on relative usage of the network elements.

5.4.6 Allocation of Residual HV Network Costs to Customer Groups

This allocation is to reflect the usage of each of the customer groups of the HV network remembering that the costs associated with users with maximum demands greater than 1,000 kVA have already been determined.

The allocation is based on the diversified maximum demand imposed by each customer group. Where a user has a metered demand, that demand is recorded but for the vast majority of users there is no metered demand. For all of these users a notional demand is calculated based on their diversified load factor. Those calculated demands are adjusted by average loss factors to reflect the actual demand placed on the HV network.

The load factors are based on industry codes that reflect typical users. These load factors were derived from sample data taken over a large number of users and are recorded against each user. The sum of the demands is called the anytime maximum demand (ATMD).

The loss factors that are used are listed by customer group as follows:

Customer Group	Loss Factor (%)
Un-metered	8
Street Lights	8
Residential	8
Small Business	8
General Business Small	8
General Business Medium	5
General Business Large	4
Low Voltage >1MVA	4
High Voltage	1

5.4.7 Fixed and Variable Costs

Based on the premise that the network was built in part to supply each user, it is reasonable to allocate some of the HV costs on a per user basis rather than purely on demand. Capacity to carry load should clearly be allocated on demand, but the cost to get a minimum capacity supply to a user should, in principle, simply be allocated on a per user basis. This reflects the principle that all users benefit from the HV line regardless of their actual usage.

The question of what percentage of costs should be allocated on a per user basis is the classical fixed and variable cost allocation issue. To determine the fixed component of the cost the approach taken will be to calculate the cost to establish the network to supply the smallest possible load to each user. The variable component of the cost can then be based on all costs that give the network capacity to provide differential supply to each user. That process is described below.

Capital related costs (return and depreciation)

The “minimal” cost HV line could be seen as a single-phase line with minimum conductor size, maximum bay lengths and minimum pole and hardware ratings. It is reasonable to assign 40 metre bays in the urban area and 250 metre bays in rural areas for this purpose. The approximate costs for such hypothetical constructions (derived from the results of the 2004 valuation study) would be as follows.

Line Construction	Cost per Kilometre ($)
1 Phase Steel (40 m bays)	18,000
3 Phase Large Size (40 m bays)	50,000
1 Phase Steel (250 m bays)	8,500
3 Phase Large Size (120 m bays)	24,000

From these numbers it is reasonable to deduce that the cost to simply provide a minimal HV supply is approximately 35% of the cost to provide a full capacity supply in both the urban and rural cases. The remaining 65% is therefore considered related to load and these capital related costs should be allocated on demand.

Operating and maintenance costs

A proportion of the costs associated with operations and maintenance do not vary with load, while other costs are clearly load related.

A proportion of maintenance costs relating to routine inspection and repair could be regarded as being fixed in nature, whereas a proportion is required to maintain capacity, and therefore could be regarded as variable. Fault restoration work can be similarly differentiated, depending on the nature of the faults.

It is difficult to be definitive in allocating maintenance costs but a 50/50 split between fixed and variable is considered reasonable and has been adopted for cost allocation purposes.

Resultant cost allocation

Applying these percentage allocations to three phase HV capital and O&M costs results in a fixed to variable ratio of approximately 40:60.

5.4.8 Allocation of Transformer Costs to Customer Groups

Transformers are installed to provide capacity and energy for each load and the costs can be fairly allocated on demand.

The cost of maintenance of transformers is a very small proportion of the total distribution network maintenance expense, and so no maintenance costs are allocated to transformers.

5.4.9 Allocation of LV Network Costs to Customer Groups

The logic for developing cost allocation principles for LV network costs is identical to the HV case. Therefore, the LV costs are allocated on a similar basis.

However, the LV costs per kVA are generally higher for smaller users than for larger users. Larger users use proportionately less of the LV network because they are typically connected closer to transformers, and generally have a lower level of back-up. For example, a user with a load of 300 kVA or more would generally be connected directly to a transformer with limited capacity in the LV network to supply only part load in the event of an HV contingency.

Appropriate weighting factors have therefore been derived to reflect the proportionate usage of the LV network by the different customer groups, as follows:

Customer Group	Cost Weighting
Residential	1
Small business	1
General business - small	1
General business - medium	0.9
General business - large	0.1
Low Voltage >1,000 kVA	0.1
High Voltage	0

5.4.10 Allocation of Tariff Equalisation Contribution (TEC) Costs to Customer Groups

TEC is allocated to the cost pools consistent with the methodology detailed above. TEC is then allocated to customers groups on the same basis that is set out above for:

1. Allocation of HV Network Costs to customer groups
2. Allocation of Transformer Costs to customer groups
3. Allocation of LV Network Costs to customer groups

5.4.11 Street Lighting Costs

Allocation of network costs to street lighting is in two components, namely the use of network costs and the costs associated with the street light asset itself.

Use of Network Costs

Street lighting does not contribute to system peak load, which occurs mid afternoon in summer. In winter, the lighting load coincides with the evening peak but because the various network elements have a higher rating in the colder conditions, street lighting effectively does not contribute to network costs but simply assists in improving the load factor.

On this basis, no transmission or distribution HV costs are allocated to street lighting. LV and transformer costs are allocated on a fixed and variable basis as for other customer groups.

Street Light Asset Costs

The allocation of the street light asset costs is based on the average cost per light, as derived in the asset valuation, applied over the total asset.

5.4.12 Metering Costs

Metering costs are determined from asset information for the various customer groups and both capital and maintenance costs are allocated on a per user basis across each group.

5.4.13 Administration Costs

The allocation of administration costs is based on specific charges for the larger customer groups, with the residual cost pool allocated by ATMD over the other customer groups.

5.5 Cost Pool Allocations

Applying the above methodology, the following tables detail the allocation of the distribution network revenue entitlement (which includes TEC) to the cost pools and customer groups:

Table 8 - Distribution Cost Pools for 1 March to 30 June 2010 ($M Nominal Annualised)

	Locational Zone					
Cost Pool	CBD	Urban	Goldfields Mining	Mixed	Rural	Total
High Voltage Network	3.6	78.8	2.4	56.9	68.0	209.7
High Voltage Network > 1,000 kVA	5.1	16.4	1.9	6.0	2.4	31.9
High Voltage Network Total	**8.8**	**95.2**	**4.4**	**62.9**	**70.4**	**241.6**
Low Voltage Network	5.5	91.9	0.9	25.8	11.0	135.1
Transformers	3.5	33.2	0.9	16.7	11.9	66.2
Streetlight Assets						16.2
Metering						33.3
Administration						79.0
TOTAL Reference Service Revenue						**571.4**

Table 9 - Distribution Customer Groups for 1 March to 30 June 2010 ($M Nominal Annualised)

								High Voltage Network		Low Voltage Network		Transformers	Streetlight Assets	Metering	Administration
Customer Group	ATMD MVA	GWh	Loss Adjusted ATMD's	Transformer Adjusted ATMD's	LV Adjusted ATMD's	Number of Customers	LV Adjusted Customer Numbers	Fixed $/annum	Variable $/annum	Fixed $/annum	Variable $/annum	Variable $/annum	Fixed		
Unmetereds	5	34	6	6	6	15,266	15,266	0.9	0.2	0.7	0.1	0.1	0.0	0.0	0.3
Streetlights	27	107	29	29	3	217,642	21,764	1.6	0.9	0.9	0.1	0.4	16.2	0.0	0.7
Residential	1,823	5,114	1,975	1,975	1,975	807,334	807,334	53.2	63.0	34.4	49.8	29.3	0.0	24.1	39.3
Small Business	501	1,144	524	524	524	81,534	81,534	9.6	21.6	3.5	13.3	8.9	0.0	4.7	9.1
General Business - Small	795	1,605	832	832	832	16,236	16,236	1.3	28.8	0.7	20.9	13.0	0.0	2.5	13.1
General Business - Medium	389	856	407	407	367	2,617	2,355	0.2	12.6	0.1	9.1	6.0	0.0	0.9	6.3
General Business - Large	278	814	287	287	29	544	54	0.0	8.8	0.0	0.7	4.3	0.0	0.3	4.3
LV greater than	246	597	255	255	25	124	12	1.7	10.4	0.0	0.6	4.2	0.0	0.2	1.7

								High Voltage Network		Low Voltage Network		Transformers	Streetlight Assets	Metering	Administration
Customer Group	ATMD MVA	GWh	Loss Adjusted ATMD's	Transformer Adjusted ATMD's	LV Adjusted ATMD's	Number of Customers	LV Adjusted Customer Numbers	Fixed $/annum	Variable $/annum	Fixed $/annum	Variable $/annum	Variable $/annum	Fixed		
1000kVA															
HV less than 1000kVA	44	150	45	0	0	76	0	0.0	1.2	0.0	0.0	0.0	0.0	0.1	0.6
HV>1000	770	2,891	787	0	0	263	0	8.7	17.0	0.0	0.0	0.0	0.0	0.5	3.6
TOTAL	**4,879**	**13,312**	**5,146**	**4,315**	**3,761**	**1,141,635**	**944,556**	**77.1**	**164.5**	**40.4**	**94.7**	**66.2**	**16.2**	**33.3**	**79.0**

6 Reference Tariff Structure

This section provides an overview of the reference tariffs that apply to the transmission and distribution system.

6.1 Reference Services & Tariff Structure

The following table details the relationship between the reference services, detailed in the Access Arrangement, and the reference tariffs.

Table 10 - Reference Services

Reference Service	Reference Tariff
A1 – Anytime Energy (Residential) Exit Service	RT1
A2 – Anytime Energy (Business) Exit Service	RT2
A3 – Time of Use Energy (Residential) Exit Service	RT3
A4 – Time of Use Energy (Business) Exit Service	RT4
A5 – High Voltage Metered Demand Exit Service	RT5
A6 – Low Voltage Metered Demand Exit Service	RT6
A7 – High Voltage Contract Maximum Demand Exit Service	RT7
A8 – Low Voltage Contract Maximum Demand Exit Service	RT8
A9 – Streetlighting Exit Service	RT9
A10 –Un-Metered Supplies Exit Service	RT10
A11 – Transmission Exit Service	TRT1
B1 – Distribution Entry Service	RT11
B2 – Transmission Entry Service	TRT2
C1 – Time of Use Energy (Residential) Bidirectional Service	RT12

6.2 Exit Service Tariff Overview

An overview of the structure of each of the reference tariffs applicable to exit services is presented in the following sections.

6.2.1 RT1 – Anytime Energy (Residential)

The tariff structure for distribution is based on:

- A fixed charge per user, and
- A charge per kWh for calculated energy consumption.

The tariff structure for transmission is based on:

- A charge per kWh for calculated energy consumption.

Energy only tariffs have no incentive for users to improve their load factor or shift energy consumption to off-peak.

6.2.2 RT2 – Anytime Energy (Business)

The tariff structure for distribution is based on:

- A fixed charge per user, and
- A charge per kWh for metered energy consumption.

The tariff structure for transmission is based on:

- A charge per kWh for metered energy consumption.

Energy only tariffs have no incentive for users to improve their load factor or shift energy consumption to off-peak

6.2.3 RT3 – Time of Use Energy (Residential)

The tariff structure for distribution is based on:

- A fixed charge per user;
- A charge per kWh for metered on peak energy consumption; and
- A charge per kWh for metered off peak energy consumption.

The tariff structure for transmission is based on:

- A charge per kWh for metered on peak energy consumption; and
- A charge per kWh for metered off peak energy consumption.

Time of use tariffs have the incentive for users to manage their energy consumption to shift energy consumption from on-peak to off-peak.

6.2.4 RT4 – Time of Use Energy (Business)

The tariff structure for distribution is based on:

- A fixed charge per user;
- A charge per kWh for metered on peak energy consumption; and
- A charge per kWh for metered off peak energy consumption.

The tariff structure for transmission is based on:

- A charge per kWh for metered on peak energy consumption; and
- A charge per kWh for metered off peak energy consumption.

Time of use tariffs have the incentive for users to manage their energy consumption to shift energy consumption from on-peak to off-peak.

6.2.5 RT5 – High Voltage Metered Demand

The tariff structure is based on the metered demand of the user, with a discount to the demand charge based on the ratio of off peak energy to total energy used. In addition the tariff has a demand length tariff component for users with demand greater than 1,000 kVA. There is a separate metering charge that picks up the capital and operating costs for the metering asset.

This tariff has a mix of incentives for the user to manage their electricity consumption.

The demand used is a running 12-month peak. This provides a clear incentive to manage the peak demand because any excessive demand recorded in one month then impacts upon the demand charge for the next 12 months. The demand length charge is also based on the running 12-month peak.

The second incentive is the off peak energy discount which is based upon the ratio of off peak energy to total energy used. The maximum discount is 50% for off peak energy usage only and for an equal use of on and off peak energy the discount is 25%.

6.2.6 RT6 – Low Voltage Metered Demand

The tariff structure is identical to RT5 – High Voltage Metered Demand.

6.2.7 RT7 – High Voltage Contract Maximum Demand

The tariff structure requires the user to nominate a contracted maximum demand (CMD) that reasonably reflects their expected annual peak demand. In addition the tariff has a demand length tariff component also based on the CMD. There is a monthly penalty for any demand excursion above the CMD. All prices are in terms of $ per kVA.

The distribution component of the prices is zonal and there are 5 zones ranging from CBD to rural. This is because the costs of supply are seen to be dependent on the nature of the network that varies according to the location and consequent construction standard and cost.

There are also separate charges for administration and metering.

The transmission component of the tariff is nodal with prices based on the zone substation to which the user is connected.

This tariff has a mix of incentives for the user to manage their electricity consumption.

The demand is in kVA rather than kW so that there is a clear benefit from managing the power factor as close to unity as possible. For example, improving the power factor from 0.7 to 0.8 will reduce the demand charge by 12.5%.

The second incentive is to manage the peak demand, which can be achieved by improving the load factor and by containing the peak demand. This incentive is very strong and the user has flexibility in the options available for managing the demand. The penalty for exceeding the contract maximum demand provides additional incentive.

The demand length charge provides an incentive for the user to locate as close as possible to the zone substation. For existing users there is no real opportunity to respond to this incentive, but for new users there is some ability to respond.

The transmission component of the price is nodal so that there is a clear signal for users to locate near to the lower price substations. This may or may not be achievable depending on the individual user circumstances.

6.2.8 RT8 – Low Voltage Contract Maximum Demand

The tariff structure is identical to RT7 – High Voltage Contract Maximum Demand with the addition of a low voltage charge that reflects the cost of usage of the low voltage distribution network.

6.2.9 RT9 – Streetlighting

Street-lights do not have metering information to support either the initial setting of the tariff or the billing of users based on energy consumption or energy demand and therefore the energy consumption must be estimated.

The tariff structure for distribution is based on:

- A fixed charge per user; and
- A charge per kWh for calculated energy consumption.

The tariff structure for transmission is based on:

- A charge per kWh for calculated energy consumption.

In addition there is a charge to reflect the capital and operating costs of the street light asset itself. Western Power owns the assets and the revenue is included within the reference service revenue. The tariff structure for the street light asset is simply a fixed charge per light based on the type and rating of the light.

6.2.10 RT10 – Un-Metered Supplies

Un-metered supplies do not have metering information to support either the initial setting of the tariff or the billing of users based on energy consumption or energy demand. However there is a requirement for the user to provide sufficient load data so that the energy consumption can be calculated. As such the available information is user connection and energy consumption.

The tariff structure for distribution is based on:

- A fixed charge per user; and
- A charge per kWh for calculated energy consumption.

The tariff structure for transmission is based on:

- A charge per kWh for calculated energy consumption.

6.2.11 TRT1 – Transmission

The tariff is based on the zone substation to which the user is connected. The user will pay the “use of system”, “common service” and “control system service” charges. There is also a separate metering charge. All prices are in $ per kW.

The tariff structure requires the user to nominate a contract maximum demand (CMD), in kWs, that reasonably reflects their expected annual peak demand. There is a monthly penalty for any demand excursion above the CMD.

The incentive is clearly for the user to manage their peak demand through the initial nomination of the CMD and also the monthly penalty for exceeding the CMD.

6.3 Entry Service Tariff Overview

An overview of the structure of each of the reference tariffs applicable to entry services is presented in the following sections.

6.3.1 RT11 – Distribution

The transmission charge is identical to the charge for a transmission connected generator in that the generator nominates a declared sent out capacity (DSOC) and the charge is based on the transmission nodal price at the nearest transmission entry point. The transmission charge for “use of system” is in $ per kW. Unlike transmission exit reference tariff (TRT1) there is no “common service” charge. The generator must also pay the connection charge which is also expressed in terms of $ per kW.

The generator DSOC is in kW and is corrected for losses from the zone substation to the generator site, for purposes of calculation of the transmission price component.

The distribution charge is based on the zonal CMD demand length price. There is no demand only charge. As such the distribution charge for generators with demand less than 1,000 kVA is zero. There is also a separate metering charge.

The DSOC must be nominated in kW for the transmission charge and in kVA for the distribution charge. However the power factor is assumed to be unity for the purpose of charging because the power factor will not generally be within the control of the generator.

The incentive for the distribution-connected generator is to locate as near as possible to the zone substation although for generators with a DSOC less than 1,000 kVA there is no such incentive. However small generators are not considered to require strong locational incentives because the network will generally not be impacted to any significant extent.

There is also the locational signal for the transmission component of the charge. Generators may or may not be able to respond to this signal depending on their individual circumstances.

6.3.2 TRT2 – Transmission

The tariff is based on the zone substation to which the generator is connected. The generator will pay the entry point “use of system” and “control system service” charges. There is also a separate metering charge. All prices are in $ per kW.

The tariff structure requires the generator to nominate a declared sent out capacity (DSOC), in kWs, that reflects their maximum intended export capacity. There is a monthly penalty for any demand excursion above the DSOC.

6.4 Bidirectional Service Tariff Overview

An overview of the structure of each of the reference tariffs applicable to bidirectional services is presented in the following sections.

6.4.1 RT12 – Time of Use Energy (Bidirectional Residential)

The tariff structure for distribution is based on:

- A fixed charge per user;
- A charge per kWh for metered on peak energy consumption;
- A charge per kWh for metered shoulder energy consumption; and
- A charge per kWh for metered off peak energy consumption.

The tariff structure for transmission is based on:

- A charge per kWh for metered on peak energy consumption;
- A charge per kWh for metered shoulder energy consumption; and

- A charge per kWh for metered off peak energy consumption.

Time of use tariffs have the incentive for users to manage their energy consumption to shift energy consumption from on-peak to shoulder or off-peak.

7 Derivation of Transmission System Tariff Components

This section describes the methodology used to calculate transmission reference tariff components.

7.1 Cost Reflective Network Pricing

7.1.1 General

The Cost Reflective Network Pricing (CRNP) cost allocation method allocates the revenue requirement to all network elements, based on their Gross Optimised Deprival Value (GODV), then determines the use made of each network element by each connection point during the survey period.

The Cost Reflective Network Pricing cost allocation process requires detailed network analysis and involves the following steps:

1. determining the annual revenue requirement (ARR) for individual transmission shared network assets (see below);

2. determining the network load and generation pattern;

3. performing a load-flow to calculate the MVA loading on network elements;

4. determining the allocation of generation to loads;

5. determining the utilisation of each asset on the network by each connection point;

6. allocating the revenue requirement of individual network elements to each user based on the assessed usage share; and

7. determining the total cost allocated to each connection point by adding the share of the costs of each individual network element attributed to each point in the network.

7.1.2 Allocation of Generation to Load

A major assumption in the use of the CRNP methodology is the allocation of generation to load using the ‘electrical distance’. With this approach, a greater proportion of load at a particular location is supplied by generators that are electrically closer than those that are electrically remote. The ‘electrical distance’ is the impedance between the two locations, and this can readily be determined through a standard ‘fault level calculation’. Once the assumption has been made as to the proportion that each generator actually supplies each load for a particular load and generation condition (time of day) it is possible to trace the flow through the network that results from supplying each load (or generator).

The utilisation that any load makes of any element is then simply the ratio of the flow on the element resulting from the supply to this load to the total flow on the element made by all loads and generators in the system.

7.1.3 Operating Conditions for Cost Allocation

The choice of operating conditions is important in developing prices using the CRNP methodology. The use made of the network by particular loads and generators will vary depending on the load and generation conditions on the network at the time. The National

Electricity Rules (NER) sets out the principles to apply in determining the sample of operating conditions considered.

The load and generation patterns used to establish transmission prices should include all operating scenarios that result in most stress in the network and for which network investment may be contemplated. The operating conditions chosen should broadly correspond to the times at which high demands drive network expansion decisions. Operating conditions should be included that impose peak loading conditions on particular elements, recognising that these may occur at times other than for peak demand.

Consistent with these principles, the operating conditions to be used for the cost allocation process for the transmission system as are as follows:

- Load and generation conditions shall be actual operating conditions from the previous 12 months; and
- Operating conditions shall include data for every node for every half hour where system peak demand is greater than an amount such that data from 10 individual summer days and 10 individual winter days are included.

7.2 Price Setting for Transmission Reference Services

Transmission tariffs for exit and entry services are fixed and are generally expressed as $/kw/annum. Generally, transmission prices are derived by dividing the cost pool, either in its entirety or at a zone substation level, by the assigned maximum demand applying to those assets. However, the details of some parts of the process are complex and explained in more detail in the following sections.

7.2.1 Transmission Pricing Model

Once Transmission assets are valued and T-price has established the relativity of UOS prices the Transmission Pricing Model is used:

1. to calculate the annual revenue requirements for all respective cost pools (based on valuation data and the rate of return required); and
2. to scale the raw T-price UOS prices to give the required Use Of System cost pool revenues.

7.2.2 Connection Price

The Connection Price is an average price for the utilisation of Western Power owned connection assets. The Connection Price is uniform for all entry and exit points and reflects the total annual costs allocated to the connection assets divided by the total usage at each point. The Connection Price is calculated by taking the Connection Cost Pool Revenue and dividing it by the aggregate of relevant CMDs or DSOCs (over all Exit or Entry points where the charge is applied).

Connection charges for connection points on the transmission system are not published but are determined subject to the specific connection arrangements. These connection charges are individually calculated to reflect the actual connection assets that apply to that user. The amount of the charge is based on achieving a regulated return on all relevant assets and an allocation of the transmission network operating costs.

7.2.3 Use of System Prices

Consistent with the NER, the proportion of the transmission reference service revenue that is for Transmission UOS is allocated to each and every connection point using a Cost Reflective Network Pricing method (CRNP). CRNP assigns a proportion of shared network costs to individual user connection points.

The relativity of Use of System prices for both exit and entry points is calculated using 'T-price' (see below for details). Raw T-price UOS prices are applied to all users based on forecast CMDs and DSOCs and scaled to give the required relevant Cost Pool Revenue.

T-Price

Western Power uses T-price to establish the relativity of Use Of System (UOS) prices for each exit and entry point. T-price is a modelling tool to allocate network costs to each node using Cost Reflective Network Pricing. T-price requires significant work to establish all of the inputs and to run the model. However, in summary:

- The GODV of every branch and node of the network is allocated. Every node is classified as either Exit or Entry, and every Branch is classified as either shared, or dedicated to consumers or dedicated to generators.
- Electrical configuration and parameters of the network are established (PSSE system Raw Data file).
- Interval demand data is assembled for every node.
- Load flow analysis is carried out so that all of the network element costs are allocated to each zone substation based on usage of those network elements. This process derives an annual cost for each node.
- The costs at each node are then converted to prices by assigning a maximum demand to each node and using that demand to calculate a price in terms of $/kW/annum.

UOS – Exit Points

Use of System prices for Exit Points are calculated by scaling raw T-price UOS prices for Exit Points to recover the Use of System for Loads Cost Pool Revenue.

UOS – Entry Points

Use of System prices for Entry Points are calculated by scaling raw T-price UOS prices for Entry Points to recover the Use of System for Generators Cost Pool Revenue.

7.2.4 Common Service Price for Loads

The Common Service Price is expressed in $/kW/annum and is uniform for all exit points. The Common Service Price is calculated by taking the Common Service Cost Pool Revenue and dividing it by the aggregate of relevant Contract Maximum Demands (over all Exit points where the charge is applied).

7.2.5 Control System Service Price

The Control System Service Price is expressed in $/kW/annum. Separate Prices for consumers and generators are calculated based on the respective cost pools but are uniform for each.

CSS for Consumers

The Control System Services price to Loads is calculated by taking the Control System Services to Loads Cost Pool Revenue and dividing it by the aggregate of relevant Contract Maximum Demands (over all Exit points where the charge is applied).

CSS for Generators

The Control System Services price for Generators is calculated by taking the Control System Services to Generators Cost Pool Revenue and dividing it by the aggregate of relevant Declared Sent Out Capacities (over all Entry Points where the charge is applied).

7.2.6 Transmission Reference Tariff Setting

The following table details the forecast transmission revenue, by tariff, which will be collected from transmission connection points and the total amount that will be collected from distribution connection points (please see section 7.3 for further details).

Table 11 - Transmission Revenue Forecast for 1 March to 30 June 2010 ($M Nominal Annualised)

	Forecast Total MW	Number Customers	Forecast Transmission Revenue Recovered
TRT1 – Transmission Exit	540	27	22.6
TRT2 – Transmission Entry (includes LV Gens etc.)	5351	26	52.6
RT1 – RT 11 - Distribution Users (Pass Through)	3796	1,141,648	210.5
Deduct Standby			-0.5
TOTAL			**285.2**
Forecast under-recovery (compared to Annualised Transmission Reference Service Revenue of $286.8M)			**1.6**

Western Power considers that the differences between required and forecast revenues from reference services are within a reasonable margin when determining a complex set of reference tariffs. Western Power also notes that, under the price control of the access arrangement, any differences between required and actual revenues will be corrected for in transmission and distribution prices in future pricing years.

Note: The standby revenue relates to Western Power providing standby services. This revenue has been deduced from the reference service revenue due to the standby service being provided as a non-reference service.

7.3 Price Setting for Distribution Reference Services

The tariffs for connection points on the transmission system do not collect the full transmission reference service revenue entitlement. Connection points on the distribution system utilise the transmission system as well as the distribution system. The remainder of the transmission reference service revenue entitlement is collected from tariffs for connection points on the distribution system.

Charges are determined for each direct connected transmission user based on respective Contract Maximum Demands (CMDs). The revenues from these users are then deducted from the revenue entitlement for that substation to give a net revenue amount to be recovered from users connected to that substation via tariffs for connection points on the distribution system.

Reference tariffs for users connected to the distribution system with a peak demand >1MVA incorporate transmission nodal prices. The transmission pass-through revenue, net of the revenues from the >1MVA users, is then allocated in aggregate to the various small customer groupings on the basis of loss adjusted any time maximum demand (ATMD) for each grouping (further described below).

A number of processes take place to determine transmission prices that match the structure of distribution reference tariffs so that a full suite of bundled tariffs can be produced.

Transmission prices take a range of forms. The CMD tariffs are based on a nominated peak demand in terms of kVA. The CMD tariffs are nodal in that they are based on the transmission node to which the load user is connected. All other tariffs are uniform across the SWIN.

7.3.1 Flow Chart

The process to derive prices can be illustrated in the following flow diagram.

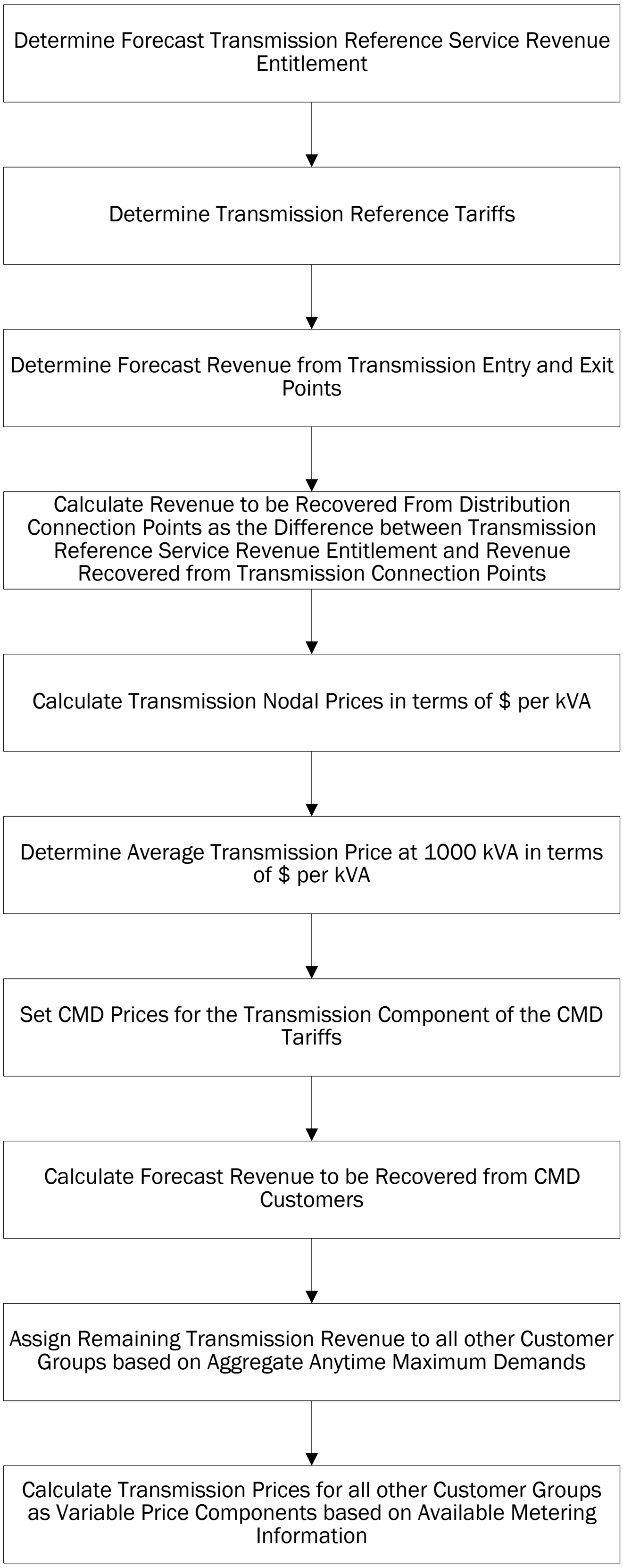

Figure 3 - Derivation of Transmission Tariff Component of Distribution System Flow Chart

Each step in this process to derive transmission component of the distribution system reference tariffs is described in more detail as follows. The first two steps of determining the revenue entitlement and prices for transmission connected users have been covered earlier.

7.3.2 Calculate the Forecast Revenue to be recovered from Distribution-Connected Users

It is assumed at this stage that the forecast transmission revenue entitlement has been determined and transmission reference tariffs set. By applying the reference tariffs to the forecast transmission-connected user data, the revenue to be recovered from transmission entry and exit points can be forecast. The residual is the revenue that must be recovered from connection points on the distribution system.

7.3.3 Calculate Transmission Nodal Prices in Terms of $ per kVA

To calculated the transmission prices in terms of $ per kVA the zone substation power factors must be determined. The power factors are measured at the low voltage bus of the zone substations at system peak. To create a single nodal price the transmission use of system, common service and connection prices are added together for each zone substation. Multiplying that price by the power factor then provides the price in terms of $/kVA.

There is an additional factor taken into account at this stage. The Urban and CBD prices are set to be uniform for distribution-connected users. To achieve this, a weighted average transmission nodal price and a weighted average power factor are used.

This step is taken for two primary reasons. It does not make sense for users across the Perth metropolitan area to see a range of prices depending on location. For example users can be connected to one zone substation for a period of time and then transferred to a different zone substation for operational reasons. Individual zone substation nodal prices would result in such a user seeing a price change although they had not changed anything from their perspective. From an administrative perspective it would be very difficult to manage such a situation. Price changes would also need to be managed within any side constraints imposed on price movements.

The second reason is that nodal prices are designed to give users an economic signal in terms of location. However, in an urban environment it is difficult for users to respond to any economic signal because land zoning and availability will normally be the determining factor in location rather than cost of supply.

This process produces a set of zone substation prices that are individual for Rural, Mixed and Mining substations and uniform for the CBD and Urban substations. These transmission nodal prices apply to connect points on the distribution system with demands equal to or greater than 7,000 kVA. This principle is established because the cost that a 7,000 kVA user imposes on the transmission network will be the same whether connected to the distribution or transmission networks.

For users with CMD below 7,000 kVA the factor of load diversity becomes more relevant. In addition, the price must be structured to fit into the bundled tariff structure for all CMD users with demands greater than 1,000 kVA.

7.3.4 Determine Average Transmission Price at 1,000 kVA

At this stage we have the transmission nodal prices at 7,000 kVA. We also have established that the transmission price in terms of $/kVA at 1,000 kVA will be uniform for all users and will be the same from 0 to 1,000 kVA. The task is to establish that uniform price.

Transmission costs are allocated to all users on the basis of anytime peak kVA demand. The transmission price is simply the revenue to be recovered from users with demands below 1,000 kVA divided by the sum of the anytime maximum demands of all those users.

The anytime maximum demands are not metered for the vast majority of users with demands below 1,000 kVA. The energy consumption is metered and the anytime maximum demands are estimated by applying load factors based on “Industry Codes”. The industry codes and associated load factors were developed using sample data for actual representative user types.

At this stage the size of the revenue pool is not established. The revenue pool will be the amount defined by the following formula:

$$RP_{\text{Below 1,000}} = RP_{\text{Total}} - RP_{\text{Over 7,000}} - RP_{\text{1,000 to 7,000}}$$

where,

$RP_{\text{Below 1,000}}$ = revenue to be recovered from users with demands below 1,000 kVA

RP_{Total} = revenue to be recovered from all distribution connected users

$RP_{\text{Over 7,000}}$ = revenue to be recovered from users with demands greater than 7,000 kVA

$RP_{\text{1,000 to 7,000}}$ = revenue to be recovered from users with demands between 1,000 and 7,000 kVA

This equation has unknowns in several terms at this stage. The revenue to be recovered from users with demands greater than 7,000 kVA is known because it is equal to the forecast demands of those users multiplied by the nodal price for each user.

The next step is to determine the pricing structure for users with demands between 1,000 and 7,000 kVA. To facilitate the bundling of transmission and distribution components in reference tariffs for connection points on the distribution system the transmission price structure must be consistent with the distribution price structure. For these users this means the prices will be in “rate block” structure and take the form:

$$\text{User Charge}_{\text{1,000 to 7,000}} = (\text{Price}_{\text{At 1,000}} * 1{,}000\text{ kVA}) + (\text{Price}_{\text{1,000 to 7,000}} * (\text{CMD}_{\text{User}} - 1{,}000\text{ kVA}))$$

Where:

$\text{User Charge}_{\text{1,000 to 7,000}}$ = the use of system charge for a user with CMD between 1,000 and 7,000 kVA

$\text{Price}_{\text{At 1,000}}$ = the average use of system price for all users with CMD below 1,000 kVA

$\text{Price}_{\text{1,000 to 7,000}}$ = the use of system for this user with CMD between 1,000 and 7,000 kVA

CMD_{User} = the contract maximum demand for that user

The $\text{Price}_{\text{1,000 to 7,000}}$ will be different for each zone substation but can be calculated by the formula:

$$\text{Price}_{1,000\text{ to }7,000} = [(\text{Price}_{\text{At }7,000} * 7,000\text{ kVA}) - (\text{Price}_{\text{At }1,000} * 1,000\text{ kVA})]/6,000\text{ kVA}$$

So we now have a formula to calculate the price for each user with CMD between 1,000 and 7,000 kVA with the unknown being the price at 1,000 kVA. We now have a single unknown (Price At 1,000) that can now be solved in the above equation which now must be expanded as below.

Original Equation:

$$RP_{\text{Below }1,000} = RP_{\text{Total}} - RP_{\text{Over }7,000} - RP_{1,000\text{ to }7,000}$$

Expansion of each term:

$RP_{\text{Below }1,000}$ = ∑ User anytime maximum demands multiplied by Price At 1,000

RP_{Total} = Total transmission revenue entitlement allocated to distribution-connected users

$RP_{\text{Over }7,000}$ = ∑ Individual demands for users greater than 7,000 kVA anytime maximum demands multiplied by the nodal price at the zone substation to which the user is connected

$RP_{1,000\text{ to }7,000}$ = ∑ User charges for all users with CMDs between 1,000 and 7,000 kVA

At this stage of the process we have the average price at and below 1,000 kVA, the nodal price for each zone substation for demands between 1,000 and 7,000 kVA and the nodal price for demands greater than 1,000 kVA. This has set the transmission tariffs for CMD users.

The rate blocks were developed using the principle of a straight-line transition from the charge at 1,000 kVA to the charge at 7,000 kVA. When converted back to prices the actual prices at any demand can be mapped and in fact the transition from a flat price below 1,000 kVA to a flat price above 7,000 kVA is a 1/x curve. The following graph illustrates the price outcomes for the above process. A number of substations have been chosen to represent the range of prices across urban and rural substations

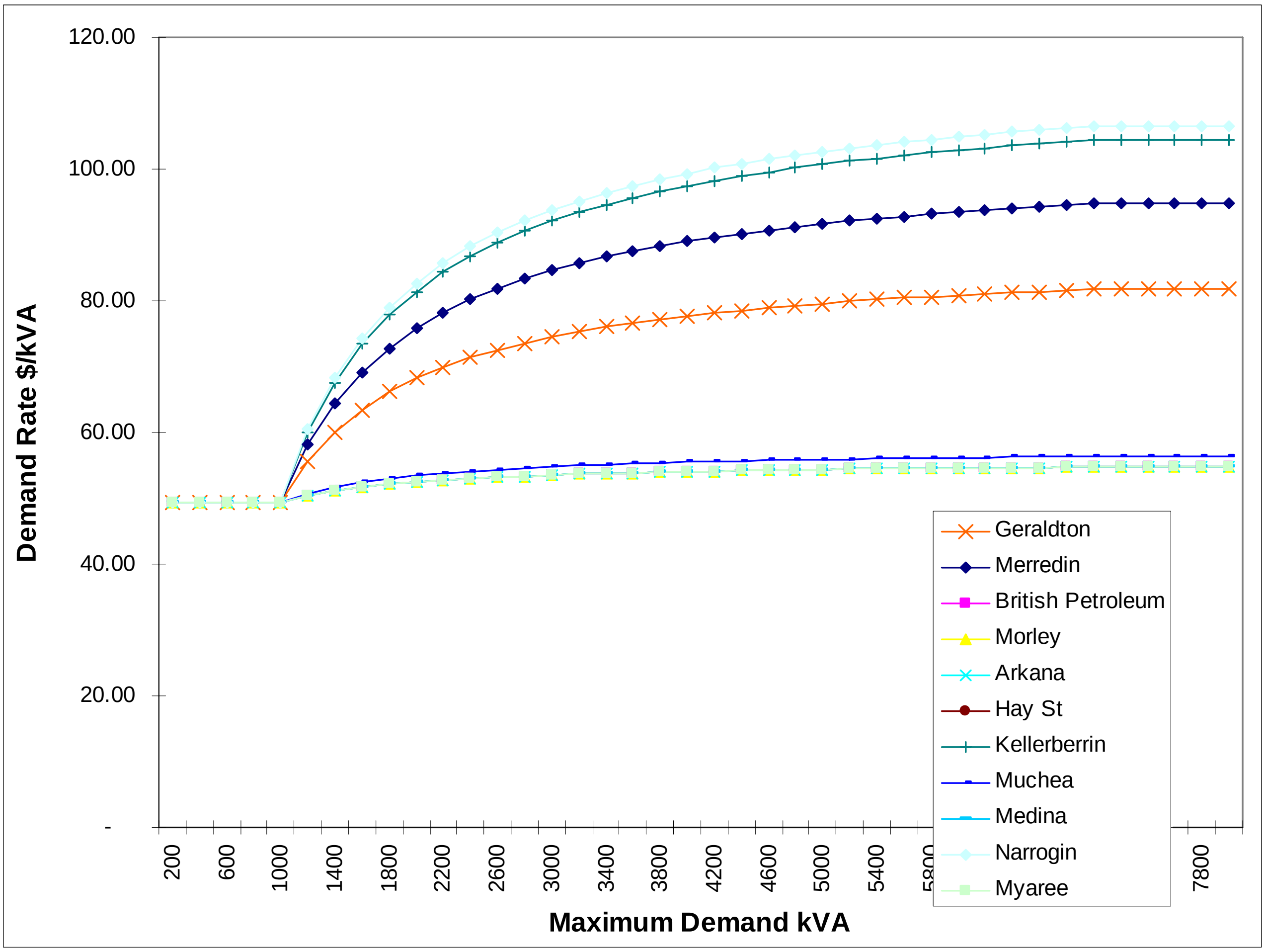

Figure 4 - Rate Blocks Example

7.3.5 Calculate Transmission Revenue to be recovered from Users with Demands below 1,000 kVA

This has been determined in the previous section in that the revenue is the average price multiplied by the sum of the anytime maximum demands of all users with demands less than 1,000 kVA.

7.3.6 Calculate Transmission Prices for all other Customer Groups

The first step in this process is to allocate the total revenue entitlement for all users with demands below 1,000 kVA to the customer groups within this category. The customer groups are restated for reference.

- General Business Large (300-1,000 kVA MD)
- General Business Medium (100-300 kVA MD)
- General Business Small (15-100 kVA MD)
- Small Business (<15 kVA MD)
- Residential
- Streetlights
- Unmetered Supplies

The result of this process is an amount of revenue that must be recovered within each customer group. At this stage the customer group users are mapped to reference tariff groups together with their associated revenues. We then have revenue entitlements assigned to reference tariffs. The process then becomes one of matching the revenue entitlement to metered information to produce tariff components.

In the case of Transmission reference tariff components the cost pools are allocated on the basis of demand. The tariffs now being considered do not have metered values for demand and on that basis; energy is used as a proxy for demand. The revenue is recovered entirely through the variable component of the tariffs, which in each of these tariffs is the energy rate. Thus the tariff components are in terms of cents per kWh.

In the case of un-metered supplies, streetlights, energy small and energy large tariffs the price is calculated by the simple formula:

$$\text{Price}_{\text{Tariff}} = \text{Forecast Revenue Entitlement Tariff /Total Forecast Energy for Tariff}$$

In the case of the time of use energy tariffs the transmission revenue allocated to those tariffs is recovered through both the on-peak and off-peak energy amounts. It is essentially the on-peak demand and therefore on-peak energy that drives the cost of the transmission network. However off-peak energy must also be served and a proportion of the revenue is recovered through the off-peak energy.

In fact approximately 30% of the forecast revenue entitlement is recovered through the off-peak energy and 70% through the on-peak energy. This ratio is chosen to achieve three outcomes:

- It clearly recovers most of the cost from on-peak usage which is the main driver of transmission costs;
- It allows for some of the costs to be recovered from off-peak energy usage to provide for equity between users with different load patterns; and
- It provides a clear economic signal to encourage off-peak energy usage that has the benefit of reducing network costs resulting in lower reference tariffs for all users.

7.3.7 Transmission Components of Distribution Reference Tariffs Forecast Revenue

The following table details the forecast transmission reference service revenue, by tariff, which will be collected from distribution connection points.

Table 12 - Transmission Reference Service Revenue Recovered from Distribution Connection Points for 1 March to 30 June 2010 ($M Nominal Annualised)

	kWh	ATMD kVA	Number Customers	Forecast Transmission Revenue Recovered
RT1 - Anytime Energy (Residential)	4,831,311,635	1,708,490	784,424	74.1
RT2 - Anytime Energy (Business)	1,606,965,332	777,905	87,969	29.6
RT3 - Time of Use Energy (Residential)	252,393,981	72,241	15,903	3.8
RT4 - Time of Use Energy (Business)	2,067,845,977	1,021,817	11,997	30.4
RT5 - High Voltage Metered Demand	290,865,102	97,671	113	4.4
RT6 - Low Voltage Metered Demand	1,074,367,905	329,878	1,038	16.1
RT7 - High Voltage Contract Maximum Demand	2,749,913,386	716,381	226	45.8

	kWh	ATMD kVA	Number Customers	Forecast Transmission Revenue Recovered
RT8 - Low Voltage Contract Maximum Demand	266,637,306	80,188	50	4.1
RT9 – Streetlighting	107,464,158	26,747	217,642	1.3
RT10 - Un-Metered Supplies	33,766,514	5,226	15,266	0.3
RT11 - Distribution Entry	0	0	13	0.0
RT12 - Time of Use Energy (Bidirectional Residential)	30,298,922	42,314	7,007	0.7
TOTAL	**13,311,830,218**	**4,878,858**	**1,141,648**	**210.5**

7.4 Annual Price Review

As described in the Access Arrangement, the reference service revenue is reviewed annually and adjusted if necessary for under or over recovery. Together with changes to user CMDs and DSOCs (including zone substation maximum demands) it is consequently necessary to adjust prices annually also.

Assets are not re-valued annually and T-price is not re-run annually, and the relativity of Use of System prices is consequently maintained. However, all new loads and generators are included and all revised forecast CMDs and DSOCs are updated in the Transmission Pricing Model annually, and prices are consequently scaled annually (within any price control side constraints) to recover the revised reference service revenue.

Transmission Use of System prices can be volatile due to matters beyond the control of any one user. In order to minimise this volatility and reduce the commercial uncertainty for users, prices are consequently subject to an annual side constraint as detailed in the Access Arrangement.

8 Derivation of Distribution System Tariff Components

This section describes the methodology used to calculate distribution reference tariff components.

The cost allocation process reflects the costs of supply for a customer group reasonably accurately. The process for determining prices for that customer group, while ideally similar in principle, is somewhat different in that it needs to take into account other factors such as equity, simplicity and efficiency (e.g. existing metering type).

Prices are determined with pre loss-adjusted ATMD's.

The Code requires uniform reference tariffs for all users with annual energy demand below 1 MVA, which equates to all but 500 within the SWIN. Users with energy demand below 1 MVA will exhibit the full range of energy consumption patterns. It is therefore clear that any tariff structure will not be totally cost reflective. However, the assumptions that are made in allocating users to particular load groups and in deriving the cost of supply to those customer groups, and the consequent prices, are all considered reasonable. Through the process described in this paper the tariff settings are derived through as rigorous a process as is possible taking into account the information available and the requirements of the Code.

The distribution reference tariff components include the costs associated with the tariff equalisation contribution (TEC). Section 7.12 of the Code sets out the requirement for Western Power to recover tariff equalisation contributions through distribution reference tariffs for exit services (Western Power has extended this to include bidirectional services to be consistent with the Code Objective). Section 8.5 details the amounts associated with TEC that are embedded within the distribution reference tariff components.

8.1 Price Setting

This section details the methodology used to derive the tariff components from the cost pools, customer groups and locational zones.

8.1.1 Tariff Components

Distribution reference tariffs have been developed to enable users with different loads and usage patterns to choose the most appropriate form for them. The tariffs have fixed and variable components and are generally compatible with existing forms of user metering.

The components of each reference tariff are shown in the following table.

Table 13 - Distribution Reference Tariff Components

TARIFF TYPE	TARIFF COMPONENTS											
	Fixed Component	Energy Only	On Peak Energy	Shoulder Energy	Off Peak Energy	Annual Metered Anytime Demand	Off Peak Discount Factor (%)	Contract Maximum Demand (CMD)	Demand/ Length for ATMD > 1,000 kVA	Fixed Metering Component	Variable Matering Component
RT1 - Energy Only (Residential)	✓	✓								✓	✓
RT2 - Energy Only (Business)	✓	✓								✓	✓
RT3 - Time of Use Energy (Residential)	✓		✓		✓					✓	✓

TARIFF TYPE	TARIFF COMPONENTS										
	Fixed Component	Energy Only	On Peak Energy	Shoulder Energy	Off Peak Energy	Annual Metered Anytime Demand	Off Peak Discount Factor (%)	Contract Maximum Demand (CMD)	Demand/ Length for ATMD > 1,000 kVA	Fixed Metering Component	Variable Matering Component
RT4 - Time of Use Energy (Business)	✓		✓		✓					✓	✓
RT5 - Metered Demand – HV	✓					✓	✓		✓	✓	
RT6 - Metered Demand – LV	✓					✓	✓		✓	✓	
RT7 - CMD – HV	✓							✓	✓	✓	
RT8 - CMD – LV	✓							✓	✓	✓	
RT9 - Street Lighting	✓	✓									
RT10 – Unmetered	✓	✓									
RT11 - Distribution Entry								✓	✓	✓	
RT12 - Time of Use Energy (Bidirectional Residential)	✓		✓	✓	✓					✓	✓

8.1.2 RT1 & RT2 - Energy Only Tariff (Residential or Business)

The tariff comprises a fixed component ($/annum) and a variable component (cents/kWh).

This is the simplest and most appropriate charging methodology for large numbers of small users with existing energy only metering.

The fixed and variable components are set to best recover the costs associated with the smaller customer groups. The tariff components for residential and business are different, reflecting the different costs of supply.

8.1.3 RT3 & RT4 - Time of Use Energy Tariff (Residential or Business)

The tariff comprises of a fixed component ($/annum) and variable on-peak and off-peak energy components (cents/kWh).

The tariff components for residential and business are different, reflecting the different costs of supply.

The fixed component of the residential TOU is set to be the same as the fixed component of the residential energy only tariff.

Analysis of system load profiles by other utilities shows that typically 70% and 30% of network costs are associated with on-peak and off-peak load respectively. The on-peak and off-peak energy components of the tariffs are set to recover these approximate proportions of the variable cost pools for the respective customer groups.

8.1.4 RT5 & RT6 - Metered Demand Tariff (HV and LV)

The metered demand tariff is based on a metered annual any time maximum demand with a discount to give credit for off peak energy usage as a proportion of total energy used.

The annual any time maximum demand is the rolling peak value over the previous 12 months. This rolling peak, rather than a monthly-metered peak, is chosen for compatibility with the CMD tariffs that are based on a contracted maximum demand set for a defined period. A tariff based on a metered monthly peak would need to be higher to recover the same revenue from these users due to the effect of seasonal variation in loads.

The principle of using this rolling peak is illustrated in the Figure 5.

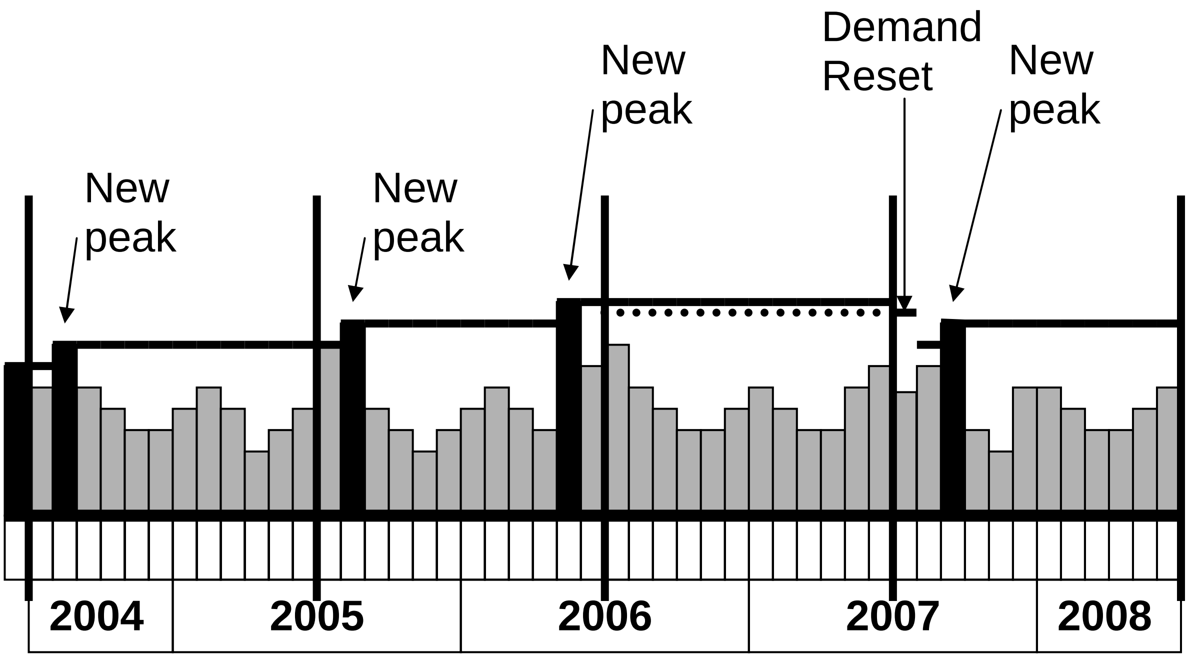

Figure 5 - Rolling Peak Illustration

There is no excess network usage charge for this tariff. The incentive to control the peak demand is significant because any half-hourly excess peak would be retained in the charges for a full 12 months. However, this is not intended to be unreasonably punitive to users and the negative impact of an extraordinary event would be assessed on a case by case basis.

The off peak discount is applied monthly, based on the metered off peak and total energy amounts. The discount is intended to create an incentive for users to use the network off-peak, and is provided as a specific reduction in the monthly charge depending on the proportion of off peak energy used.

The tariff also includes a demand-length component for demands greater than 1,000 kVA, identical to that applying in the CMD tariffs, based on the rolling annual peak.

The demand price is in rate block format. The transition points are set at 300 kVA and 1,000 kVA and the discount phases out at 1,500 kVA. At 1,500 kVA the tariff is set to be less attractive than the CMD tariffs for most users.

A discount mechanism applies to this tariff and is defined within the Price List.

8.1.5 RT7 & RT8 - Contract Maximum Demand Tariff (HV and LV)

The HV component of the CMD tariff is set to reflect a price that results in a user charge that is greater than the user incremental cost of supply but less than the stand-alone cost of supply. To achieve this outcome the two costs of service are modelled for ach of the HV and LV CMD users.

Customers on transition tariffs are modelled, for pricing setting purposes, as contract maximum demand tariff customers.

The price structure is based on two particular components. There is a component that is directly linked to the nominated maximum demand which is in terms of $/kVA. The second component is based on a combination of the maximum demand and the length of HV feeder from the zone substation to the user's connection point. This price component is expressed in terms of $/kVA.km. Both of these tariff components are set to be uniform at 1,000 kVA and to be fully cost reflective at 7,000 kVA. This structure is consistent with the transmission CMD tariff for distribution connected customers.

The "demand/length" component of the tariff cannot be used in isolation because it distorts the charge for users either very close to the zone substation, where the cost could be virtually zero, and also at a long distance from the substation, where the charge could be unreasonably high. The "demand" component of the tariff ameliorates this distortion because it recognises that the cost of supply of a user does not only relate to the distance from the zone substation but also relates to the demand that the user places on the network.

The effect of the pricing structure is that, for a fixed demand, the charge to a user increases as distance to the zone substation increases. This is effectively providing a fixed and variable component to the price for identical users depending on their distance from a zone substation. In a similar manner users at the same distance from a zone substation will pay more as their demand increases.

An additional feature of this price structure is that the price is not linear in relation to the demand.

For the demand only component, the price at 1,000 kVA is uniform for each of the locational zones and is reflective of the average HV cost of the network per KVA demand. However, as the demand increases, the price declines recognising that the cost of supply declines on a per unit basis, as the demand increases.

The demand/length component is set to zero at 1,000 kVA. This is consistent with the requirement that all tariffs are uniform below 1,000 kVA demand. The price above 7,000 kVA is uniform and the price varies continuously between 1,000 and 7,000 kVA.

In setting the CMD tariffs both components are adjusted so that for each of the users with demands greater than 1,000 kVA, their charge will fall between the incremental and stand-alone cost. The process to derive the settings is described as follows.

Demand Component of the CMD Tariff

The price at 7,000 kVA is individually set for each zone. The price is adjusted to provide a best fit so that users will see a charge that is between the incremental and stand-alone cost. This is done in combination with the demand/length component setting. However it is clear that the price at 7,000 kVA should reflect the actual costs of the networks that supply these users. As such the cost for the CBD zone will be the highest, the Urban zone the next highest and so on so that the rural zone is the cheapest.

At this stage we have the distribution nodal prices at 7,000 kVA. We also have established that the distribution price in terms of $/kVA at 1,000 kVA will be uniform for all users and will be the same from 0 to 1,000 kVA. The task is to establish that uniform price. At 1,000 kVA the demand/length price is zero so the demand price should reflect the average network price for all users in terms of $/kVA.

Distribution costs are allocated to all users on the basis of anytime peak kVA demand adjusted for losses. The distribution price is simply the revenue to be recovered from users with demands below 1,000 kVA divided by the sum of the anytime maximum demands of all those users.

The anytime maximum demands are not metered for the vast majority of users with demands below 1,000 kVA. The energy consumption is metered and the anytime maximum demands are estimated by applying load factors based on “Industry Codes”. The industry codes and associated load factors were developed using sample data for actual representative user types.

At this stage the size of the revenue pool for users with demands below 1,000 kVA is not established. The revenue pool will be the amount defined by the following formula:

$$RP_{\text{Below } 1{,}000} = RP_{\text{Total}} - RP_{\text{Over } 7{,}000} - RP_{1{,}000 \text{ to } 7{,}000}$$

where,

$RP_{\text{Below } 1{,}000}$ = revenue to be recovered from users with demands below 1,000 kVA

RP_{Total} = revenue to be recovered from all distribution users

$RP_{\text{Over } 7{,}000}$ = revenue to be recovered from users with demands greater than 7,000 kVA

$RP_{1{,}000 \text{ to } 7{,}000}$ = revenue to be recovered from users with demands between 1,000 and 7,000 kVA

This equation has unknowns in each of the terms at this stage. The revenue pools will only be determined when the CMD tariff settings are established and the prices can be applied to the forecast user data for users with demands greater than 1,000 kVA. The price at 7,000 kVA is set by graphically plotting the charge outcomes for each of the users with demands above 7,000 kVA, in the locational zones, and setting a price that puts the charge outcomes between the incremental and stand-alone cost of supply. Graphs demonstrating this are included in section 8.2.

To facilitate the solving of the remaining terms of this equation the pricing settings for users with demands between 1,000 and 7,000 kVA must be determined. The tariffs are defined in terms of “rate block” structure and, for the demand component of the tariff, take the form:

$$\text{User Demand Charge}_{1{,}000 \text{ to } 7{,}000} = (\text{Price}_{\text{At } 1{,}000} * 1{,}000 \text{ kVA}) + (\text{Price}_{1{,}000 \text{ to } 7{,}000} * (\text{CMD}_{\text{User}} - 1{,}000 \text{ kVA}))$$

where,

$\text{User Demand Charge}_{1{,}000 \text{ to } 7{,}000}$ = the demand charge for a user with CMD between 1,000 and 7,000 kVA

$\text{Price}_{\text{At } 1{,}000}$ = the average demand price for all users with CMD below 1,000 kVA

$\text{Price}_{1{,}000 \text{ to } 7{,}000}$ = the incremental demand price for this user with CMD between 1,000 and 7,000 kVA

CMD_{User} = the contract maximum demand for that user

The $Price_{1,000\ to\ 7,000}$ will be different for each locational zone but can be calculated by the formula:

$$Price_{1,000\ to\ 7,000} = [(Price_{At\ 7,000} * 7,000\ kVA) - (Price_{At\ 1,000} * 1,000\ kVA)]/6,000\ kVA$$

So we now have a formula to calculate the price for each user with CMD between 1,000 and 7,000 kVA with the unknown being the price at 1,000 kVA. The price at 7,000 kVA has been previously set.

We now have a single unknown (Price At 1,000) that can now be solved in the above equation which now must be expanded as below.

Original Equation:

$$RP_{Below\ 1,000} = RP_{Total} - RP_{Over\ 7,000} - RP_{1,000\ to\ 7,000}$$

Expansion of each term:

$RP_{Below\ 1,000}$ = ∑ User anytime maximum demands multiplied by Price At 1,000

RP_{Total} = Total HV network revenue entitlement

$RP_{Over\ 7,000}$ = ∑ Individual demands for users greater than 7,000 kVA anytime maximum demands multiplied by the zonal price at the zone substation to which the user is connected

$RP_{1,000\ to\ 7,000}$ = ∑ User charges for all users with CMDs between 1,000 and 7,000 kVA

At this stage of the process we have the average price at and below 1,000 kVA, the demand price formula for each locational zone for demands between 1,000 and 7,000 kVA and the zonal price for demands greater than 7,000 kVA. This has set the demand component of the CMD tariffs.

Demand/Length Component of the CMD Tariff

The demand/length component of the tariff is set at zero at 1,000 kVA. It is also uniform at and above 7,000 kVA. The tariff is also designed to be expressed in “rate block” format so that the price is in terms of an incremental price above 1,000 kVA and up to 7,000 kVA and a uniform price above 7,000 kVA.

The price between 1,000 and 7,000 kVA is expressed as:

$$Price_{1,000\ to\ 7,000} = [(Price_{At\ 7,000} * 7,000\ kVA) - (Price_{At\ 1,000} * 1,000\ kVA)]/6,000\ kVA$$

The price settings are established in the same process as setting the demand settings in that the incremental and stand-alone costs are graphically plotted for every CMD user within each zone and the price settings are adjusted so that the user charges fit between the limits. Graphs demonstrating this are included in section 8.2.

At this stage, the price settings are established for both the demand and demand/length price components of the CMD tariffs. The forecast HV network revenue for the HV and LV

CMD users can be calculated by applying the prices to the forecast user data and summing the charges for all users.

The prices for both the demand and demand/length components of the prices are illustrated in Figure 11.

8.1.6 Metering

The ideal way to price metering is to have a separate charge for the particular type of meter for each user. While this approach is technically feasible, it is extremely complex due to the technical and commercial variations in metering arrangements.

The alternative and more efficient approach is to use a standard metering charge in conjunction with each reference tariff to reflect the average cost of metering deployed to support application of the tariff.

However, the variation in metering costs for users within each tariff group can be marked and an average metering charge would disadvantage all smaller users. For example:

- residential users may be either single or three phase; and
- small business users with energy only or TOU energy metering may have meters direct- or CT-connected.

Therefore, it is appropriate for small users to have a charge that varies with usage and therefore reflects the variation in metering costs.

The metering price structure is as follows:

Reference Tariff Type	Metering Price
Energy	Cents/kWh & $ fixed annual charge
TOU Energy	Cents/kWh & $ fixed annual charge
Metered Demand	$ fixed annual charge
CMD	$ fixed annual charge

8.1.7 Administration

An administration charge is published separately in conjunction with the CMD tariff, but is incorporated in the variable component of all the other tariffs.

The setting of the components in the metered demand tariff ensures compatibility with the administration price for the CMD tariff.

8.1.8 RT9 - Street Lighting

Separate Network Use of System and Asset prices are designed to best recover the costs of providing streetlight services.

The use of system price comprises a fixed and variable charge similar to other low voltage tariffs, based on the expected daily cycle of energy usage.

The asset charge varies with the size and type of luminare and is based on the annualised cost of capital and maintenance associated with each.

8.1.9 RT10 - Unmetered Supplies

The unmetered supplies tariff comprises a fixed and variable charge similar to other low voltage tariffs, designed to best recover the costs of providing these services based on the expected daily cycle of energy usage.

8.1.10 RT12 - Time of Use Energy Tariff (Bidirectional Residential)

The tariff comprises of a fixed component ($/annum) and variable on-peak, shoulder and off-peak energy components (cents/kWh).

The fixed component of the residential TOU is set to be the same as the fixed component of the residential energy only tariff.

Analysis of system load profiles by other utilities shows that typically 58%, 34% and 8% of network costs are associated with on-peak, shoulder and off-peak load respectively. The on-peak, shoulder and off-peak energy components of the tariffs are set to recover these approximate proportions of the variable cost pools for the respective customer groups.

8.2 Demonstration of Derivation of Distribution Components of Distribution Reference Tariffs

8.2.1 CMD Demand Price Graphs

The following graphs illustrate that the proposed prices for the CMD tariffs are between incremental cost and stand-alone cost.

It is important to note that in the vast majority of cases the price will meet the requirements of section 7.3(b) of the Code. However, no pricing structure can be guaranteed to meet the Code requirement in every individual case. For example if the price is reduced so that the charge is below the stand-alone cost for every single customer, there emerges cases where the price is then below the incremental cost for some other customers. The prices have been set to achieve a balance between all customers, while still meeting the requirements of section 7.3(b) of the Code.

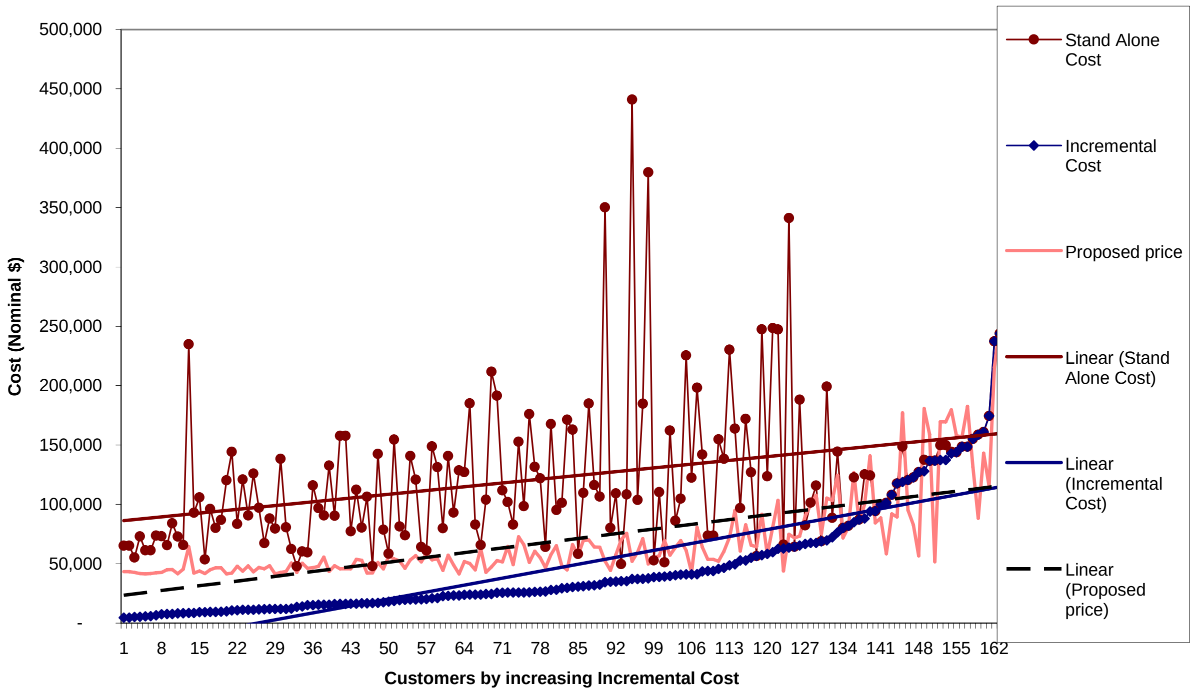

Figure 6 - Urban Zone

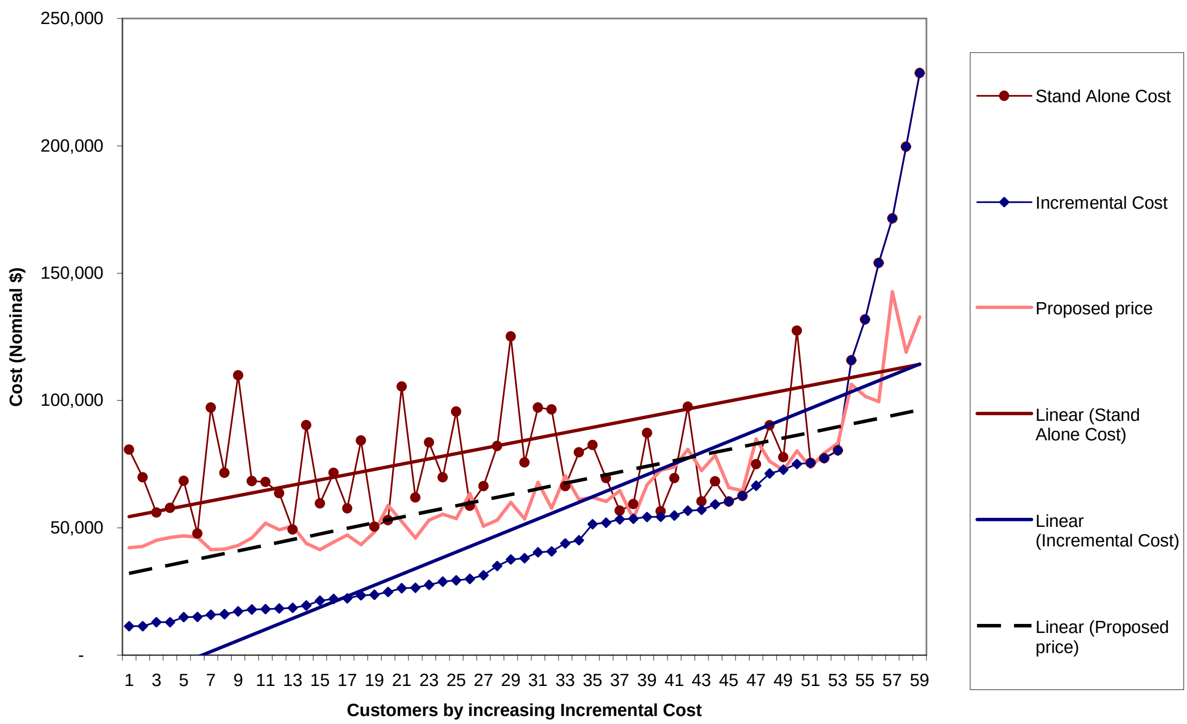

Figure 7 - CBD Zone

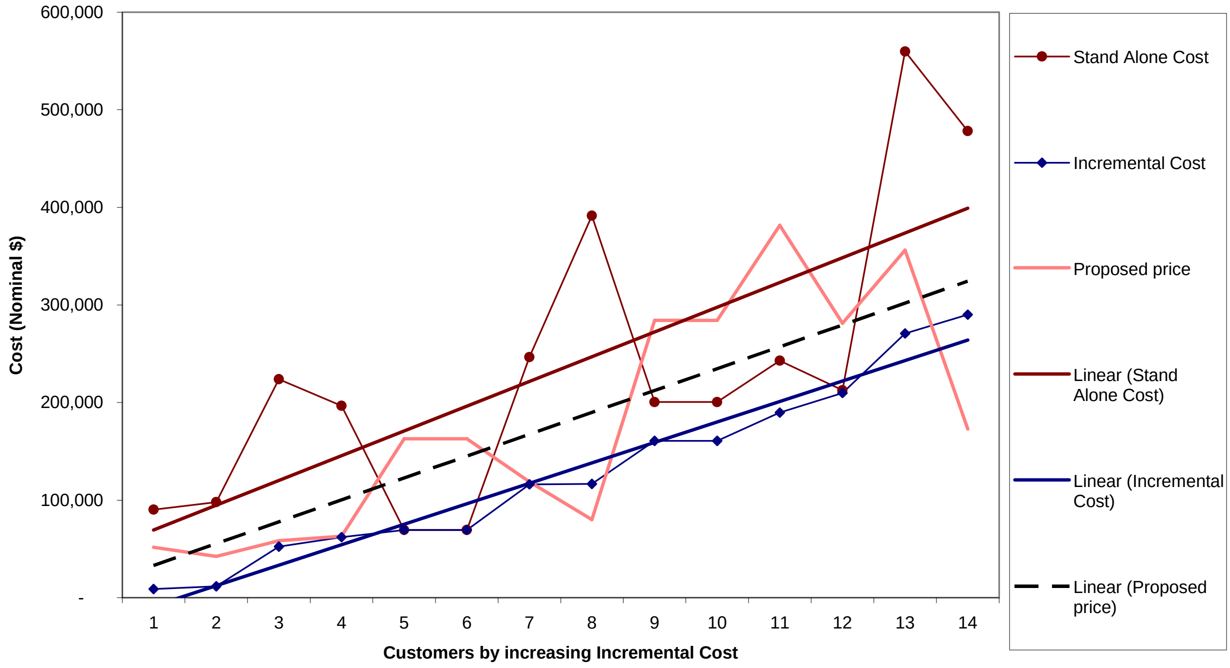

Figure 8 - Mining Zone

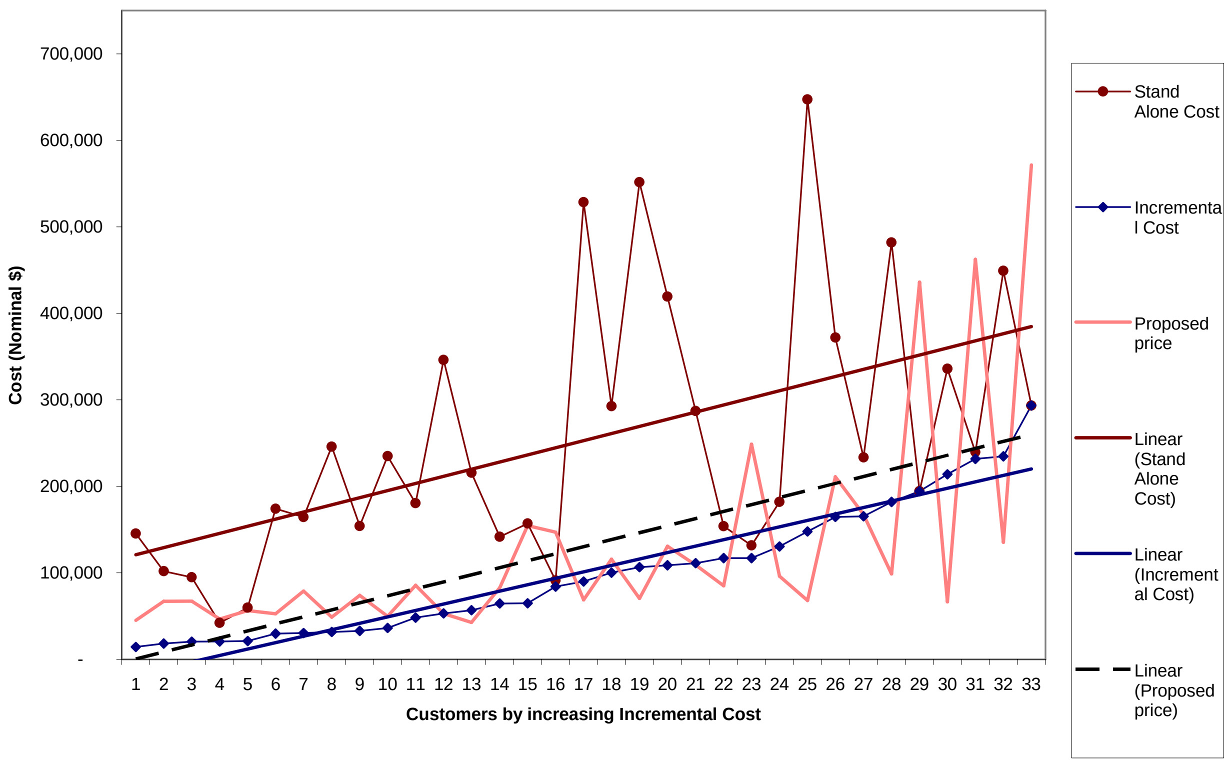

Figure 9 - Mixed Zone

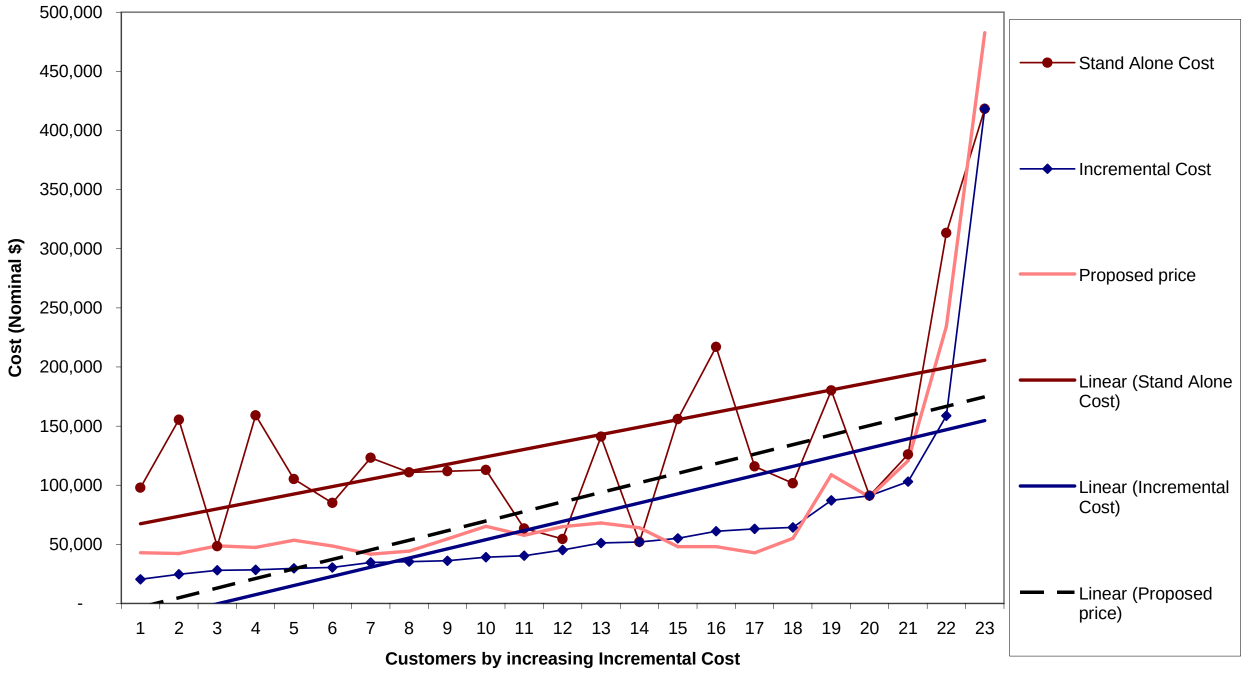

Figure 10 - Rural Zone

8.2.2 Demand/Length Graph

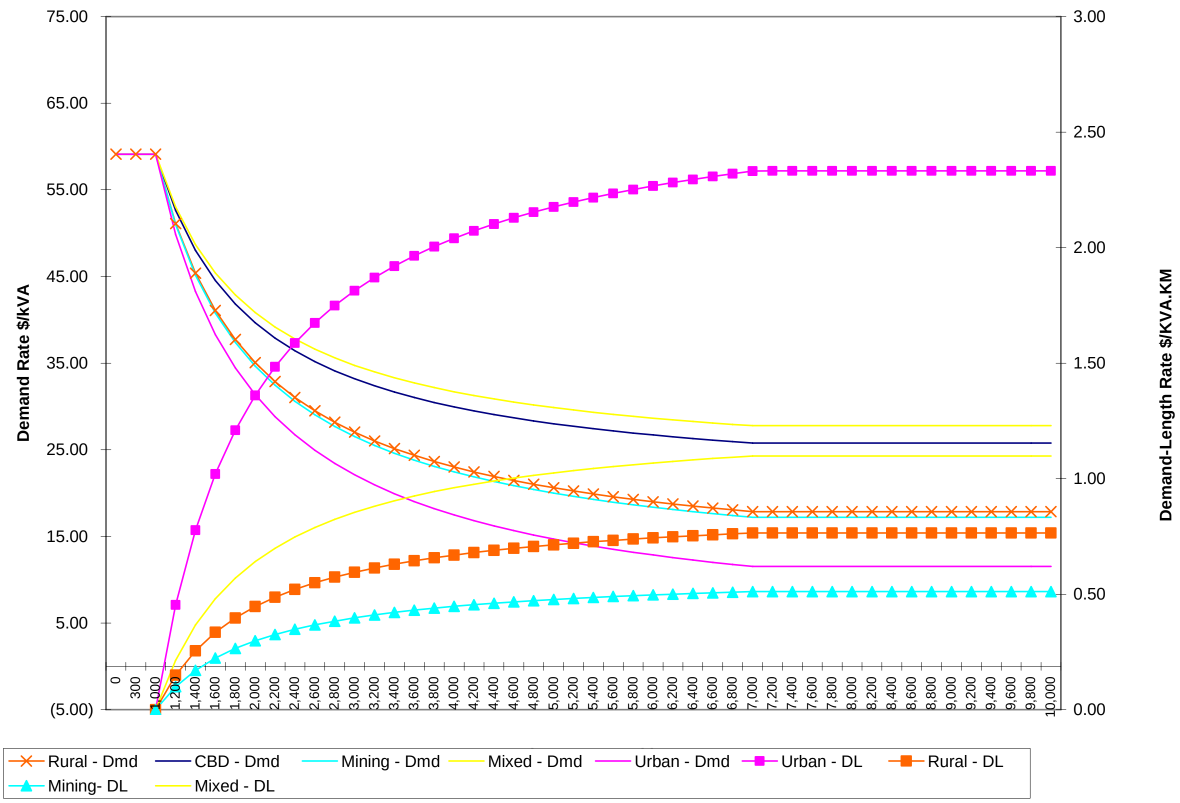

Figure 11 - Demand Length Rates & CMD Rates by Zone

8.2.3 Tariff Forecast Revenue

The following table details the forecast distribution reference service revenue, by tariff, which will be collected from distribution connection points.

Table 14 - Distribution Reference Service Revenue Recovered from Distribution Connection Points for 1 March to 30 June 2010 ($M Nominal Annualised)

	kWh	ATMD kVA	Number Customers	Forecast Distribution Revenue Recovered
RT1 - Anytime Energy (Residential)	4,831,311,635	1,708,490	784,424	301.3
RT2 - Anytime Energy (Business)	1,606,965,332	777,905	87,969	104.6
RT3 - Time of Use Energy (Residential)	252,393,981	72,241	15,903	12.2
RT4 - Time of Use Energy (Business)	2,067,845,977	1,021,817	11,997	73.1
RT5 - High Voltage Metered Demand	290,865,102	97,671	113	6.3
RT6 - Low Voltage Metered Demand	1,074,367,905	329,878	1,038	26.6
RT7 - High Voltage Contract Maximum Demand	2,749,913,386	716,381	226	25.4
RT8 - Low Voltage Contract Maximum Demand	266,637,306	80,188	50	4.9
RT9 – Streetlighting	107,464,158	26,747	217,642	19.1
RT10 - Un-Metered Supplies	33,766,514	5,226	15,266	2.0
RT11 - Distribution Entry	0	0	13	0.4
RT12 - Time of Use Energy (Bidirectional Residential)	30,298,922	42,314	7,007	2.7
TOTAL	**13,311,830,218**	**4,878,858**	**1,141,648**	**578.8**
Forecast over-recovery (compared to Annualised Distribution Reference Service Revenue of $571.4M)				**7.4**

Western Power considers that the differences between required and forecast revenues from reference services are within a reasonable margin when determining a complex set of reference tariffs. Western Power also notes that, under the price control of the access arrangement, any differences between required and actual revenues will be corrected for in transmission and distribution prices in future pricing years.

8.3 Demonstration Distribution Reference Tariffs are between incremental and stand-alone cost of service provision

In accordance with section 7.3(b) (i) and (ii) of the Code, reference tariffs are set to at least recover the incremental cost, but to be less than the stand-alone cost of service provisions.

The following table demonstrates that reference tariffs are set to at least recover the incremental cost, but to be less than the stand-alone cost of service provisions in 2009/10 in accordance with the Access Arrangement.

Table 15 - Demonstration Reference Tariffs are between incremental and stand-alone cost of service provision for 2009/10 ($M Nominal Annualised)

Reference Service	Reference Tariff	Incremental Cost of Service	Stand-alone Cost of Service Provision	Forecast Revenue Recovered from Reference Tariff
A1	RT1	277.8	404.5	375.5
A2	RT2	120.5	239.0	134.2
A3	RT3	12.7	130.3	16.1
A4	RT4	103.5	255.2	103.5
A5	RT5	7.9	118.7	10.7
A6	RT6	35.1	155.3	42.7
A7	RT7	60.7	80.4	71.1
A8	RT8	6.9	10.6	9.1
A9	RT9	19.4	134.5	20.4
A10	RT10	0.9	134.6	2.3
C1	RT12	3.3	250.3	3.3

8.4 Annual Price Review

At the end of each year, the actual distribution reference service revenue entitlement is reconciled against the actual distribution reference service revenue recovered for that year, and a correction factor applied to the forecast reference service revenue for the subsequent year. Tariffs are then adjusted/rebalanced to recover the corrected revenue for the following year and the new prices published.

Distribution prices can be volatile due to matters beyond the control of any one user. In order to minimise this volatility and reduce the commercial uncertainty for users, prices are consequently subject to an annual side constraint as detailed in the Access Arrangement.

8.5 Tariff Equalisation Contribution (TEC) in the Distribution Components of Distribution Reference Tariffs

This section details the amounts associated with TEC that are embedded within the distribution reference tariff components.

Western Power pays TEC to the WA State Government to contribute towards maintaining the financial viability of Horizon Power under Part 9A of the *Electricity Industry Act 2004*. The purpose of TEC is to enable the regulated retail tariffs for electricity that is not supplied from the South West interconnected system (SWIS) to be, so far as is practicable, the same as the regulated retail tariffs for electricity that is supplied from the SWIS.

The graphs and tables detailed in sections 8.2 and 8.3 are inclusive of TEC. The tables that follow in this section separate out just the amounts of TEC that are embedded within the distribution reference tariff components.

8.5.1 TEC Forecast Revenue

The following table details the forecast TEC, by tariff, which will be collected from distribution connection points.

Table 16 - TEC Recovered from Distribution Connection Points for 1 March to 30 June 2010 ($M Nominal Annualised)

	kWh	ATMD kVA	Number Customers	Forecast TEC Recovered
RT1 - Anytime Energy (Residential)	4,831,311,635	1,708,490	784,424	45.0
RT2 - Anytime Energy (Business)	1,606,965,332	777,905	87,969	15.0
RT3 - Time of Use Energy (Residential)	252,393,981	72,241	15,903	1.9
RT4 - Time of Use Energy (Business)	2,067,845,977	1,021,817	11,997	17.8
RT5 - High Voltage Metered Demand	290,865,102	97,671	113	2.5
RT6 - Low Voltage Metered Demand	1,074,367,905	329,878	1,038	8.8
RT7 - High Voltage Contract Maximum Demand	2,749,913,386	716,381	226	2.7
RT8 - Low Voltage Contract Maximum Demand	266,637,306	80,188	50	0.8
RT9 – Streetlighting	107,464,158	26,747	217,642	1.0
RT10 - Un-Metered Supplies	33,766,514	5,226	15,266	0.3
RT11 - Distribution Entry	0	0	13	0.0
RT12 - Time of Use Energy (Bidirectional Residential)	30,298,922	42,314	7,007	0.4
TOTAL	**13,311,830,218**	**4,878,858**	**1,141,648**	**96.1**

Western Power is required to pay $122.1M (nominal) in TEC in the 2009/10 financial year[4]. It is expected that the 2009/10 TEC components of the distribution tariff will under-recover this amount due to the side constraint. In 2008/09 Western Power was required to pay $72.0M in TEC. TEC has therefore increased by 69.6% from 2008/09 to 2009/10 however the TEC tariff components have been constrained by the side-constraint and have been uniformly scaled up by 7.5% on 1 July 2009 and by a further 17.7% from the access arrangement start date (assumed to be 1 March 2010).

[4] Western Australian Government Gazette, 25 August 2009, pg 3325

8.5.2 TEC Tariff Components – Use of System

The following table details the amounts associated with TEC that are embedded within the distribution reference tariff use of system components.

Table 17

	Fixed TEC	Variable TEC			
	c/day	c/kWh	On Peak c/kWh	Shoulder c/kWh	Off Peak c/kWh
Reference tariff 1 - RT1					
TEC	0.000	0.932	-	-	-
Reference tariff 2 - RT2					
TEC	0.000	0.932	-	-	-
Reference tariff 3 - RT3					
TEC	0.000	-	1.327	-	0.379
Reference tariff 4 - RT4					
TEC	0.000	-	1.327	-	0.379
Reference tariff 9 – RT9					
TEC	0.000	0.932	-	-	-
Reference tariff 10 – RT10					
TEC	0.000	0.932	-	-	-
Reference tariff 12 – RT12					
TEC	0.000	-	2.059	0.932	0.379

8.5.3 TEC Tariff Components – Metered Demand

The following table details the amounts associated with TEC that are embedded within the distribution reference tariff metered demand components.

Table 18

	RT5 – TEC		RT6 – TEC	
Demand (kVA) (Lower to upper threshold)	Fixed c/day	Demand (in excess of lower threshold) c/kVA/day	Fixed c/day	Demand (in excess of lower threshold) c/kVA/day
0 to 300	0.000	9.874	0.000	9.874
300 to 1000	2,962.200	9.526	2,962.200	9.526
1000 to 1500	9,630.400	3.466	9,630.400	3.466

8.5.4 TEC Tariff Components – Demand Prices

The following table details the amounts associated with TEC that are embedded within the distribution reference tariff demand components.

Table 19

Pricing Zone	RT 7 & 8 – TEC		
	Fixed charge for first 1000 kVA (c per day)	Demand charge for 1000<kVA<7000 (c/kVA/day)	Demand Charge for kVA > 7000 (c/kVA/day)
CBD	4,850.411	-0.808	0.000
Goldfields Mining	4,850.411	-0.808	0.000
Mixed	4,850.411	-0.808	0.000
Rural	4,850.411	-0.808	0.000
Urban	4,850.411	-0.808	0.000

Note: Users with demand greater than 7,000 kVA do not pay TEC. These users can usually choose between being transmission connected or distribution connected. TEC does not apply to transmission connected users. Charging TEC to distribution connected users with demand greater than 7,000 kVA would create a perverse incentive for users to transition to being transmission connected due to the addition charge. The variable demand charge between 1,000 and 7,000 kVA is negative so that when added to the fixed demand charge users with demand greater than 7,000 kVA do not pay TEC.

9 Price Changes

The following tables detail the % change in the proposed tariff components when compared to the current tariff components.

9.1 Use of System Prices

The % changes in the following table are applicable for reference tariffs: **RT1, RT2, RT3, RT4, RT9 & RT10**.

Table 20

	Fixed Price	Energy Rates		
	% Change	Anytime % Change	On Peak % Change	Off Peak % Change
Reference tariff 1 - RT1				
Transmission		12.9%	-	-
Distribution	17.7%	17.7%	-	-
Bundled Tariff	17.7%	16.2%	-	-
Reference tariff 2 – RT2				
Transmission		12.9%	-	-
Distribution	17.7%	17.7%	-	-
Bundled Tariff	17.7%	16.4%	-	-
Reference tariff 3 - RT3				
Transmission		-	12.9%	12.8%
Distribution	17.7%	-	17.6%	17.7%
Bundled Tariff	17.7%	-	16.0%	16.1%
Reference tariff 4 - RT4				
Transmission		-	12.9%	12.9%
Distribution	17.7%	-	17.7%	17.7%
Bundled Tariff	17.7%	-	16.1%	16.1%
Reference tariff 9 – RT9				
Transmission		12.9%	-	-
Distribution	17.7%	17.7%	-	-
Bundled Tariff	17.7%	16.2%	-	-
Reference tariff 10 – RT10				
Transmission		12.8%	-	-
Distribution	17.7%	17.7%	-	-
Bundled Tariff	17.7%	16.7%	-	-

The % changes in the following table are applicable for reference tariff: **TRT1**.

Table 21

Substation	TNI	Use of System Price % Change
Albany	WALB	12.9%
Alcoa Pinjarra	WAPJ	12.9%
Amherst	WAMT	12.9%
Arkana	WARK	12.9%
Australian Fused Materials	WAFM	12.9%
Australian Paper Mills	WAPM	12.9%
Baandee (WC)	WBDE	12.9%
Beechboro	WBCH	12.9%
Beenup	WBNP	12.9%
Belmont	WBEL	12.9%
Black Flag	WBKF	12.9%
Boddington Gold	WBOD	N/A
Boddington (Local)	WABD	12.9%
Boddington Reynolds	WRBD	12.9%
Boulder	WBLD	12.9%
Bounty	WBNY	12.9%
Bridgetown	WBTN	12.9%
British Petroleum	WBPM	12.9%
Broken Hill Kwinana	WBHK	12.9%
Bunbury Harbour	WBUH	12.9%
Busselton	WBSN	12.9%
Byford	WBYF	12.9%
Canning Vale	WCVE	12.9%
Capel	WCAP	12.9%
Carrabin	WCAR	12.9%
Cataby Kerr McGee	WKMC	12.9%
Chapman	WCPN	12.9%
Clarence Street	WCLN	12.9%
Cockburn Cement	WCCT	12.9%
Cockburn Cement Ltd	WCCL	12.9%
Collie	WCOE	12.9%
Collier	WCOL	12.9%
Cook Street	WCKT	12.9%
Coolup	WCLP	12.9%
Cottesloe	WCOT	12.9%
Cunderdin	WCUN	12.9%
Darlington	WDTN	12.9%
Edgewater	WEDG	12.9%
Edmund Street	WEDD	12.9%
Eneabba	WENB	12.9%
Forrest Ave	WFRT	12.9%
Forrestfield	WFFD	12.9%
Geraldton	WGTN	12.9%
Golden Grove	WGGV	12.9%
Gosnells	WGNL	12.9%
Hadfields	WHFS	12.9%

Substation	TNI	Use of System Price % Change
Hay Street	WHAY	12.9%
Herdsman Parade	WHEP	12.9%
Joel Terrace	WJTE	12.9%
Kalamunda	WKDA	12.9%
Katanning	WKAT	12.9%
Kellerberrin	WKEL	12.9%
Kojonup	WKOJ	12.9%
Kondinin	WKDN	12.9%
Kwinana Alcoa	WAKW	12.9%
Landsdale	WLDE	12.9%
Malaga	WMLG	12.9%
Mandurah	WMHA	12.9%
Manjimup	WMJP	12.9%
Manning Street	WMAG	12.9%
Margaret River	WMRV	12.9%
Marriott Road Barrack Silicon Smelter	WBSI	12.9%
Marriott Road (Local)	WLMR	12.9%
Mason Road	WMSR	12.9%
Mason Road CSBP	WCBP	12.9%
Mason Road Hismelt	WHIS	12.9%
Mason Road Kerr McGee	WKMK	12.9%
Medical Centre	WMCR	12.9%
Medina	WMED	12.9%
Merredin 66kV	WMER	12.9%
Midland Junction	WMJX	12.9%
Milligan Street	WMIL	12.9%
Moora	WMOR	12.9%
Morley	WMOY	12.9%
Mt Barker	WMBR	12.9%
Muchea Kerr McGee	WKMM	12.9%
Muchea (Local)	WLMC	12.9%
Mullaloo	WMUL	12.9%
Murdoch	WMUR	12.9%
Mundaring Weir	WMWR	12.9%
Myaree	WMYR	12.9%
Narrogin	WNGN	12.9%
Nedlands	WNED	12.9%
North Beach	WNBH	12.9%
North Fremantle	WNFL	12.9%
North Perth	WNPH	12.9%
Northam	WNOR	12.9%
O'Connor	WOCN	12.9%
Osborne Park	WOPK	12.9%
Padbury	WPBY	12.9%
Parkeston	WPRK	12.9%
Parklands	WPLD	12.9%
Piccadilly	WPCY	12.9%
Picton 66kv	WPIC	12.9%
Pinjarra	WPNJ	12.9%

Substation	TNI	Use of System Price % Change
Rangeway	WRAN	12.9%
Regans	WRGN	12.9%
Riverton	WRTN	12.9%
Rivervale	WRVE	12.9%
Rockingham	WROH	12.9%
Sawyers Valley	WSVL	12.9%
Shenton Park	WSPA	12.9%
Southern River	WSNR	12.9%
South Fremantle 66kV	WSFT	12.9%
Summer St	WSUM	12.9%
Tate Street	WTTS	12.9%
Three Springs	WTSG	12.9%
Tomlinson Street	WTLN	12.9%
University	WUNI	12.9%
Victoria Park	WVPA	12.9%
Wagerup	WWGP	12.9%
Wagin	WWAG	12.9%
Wanneroo	WWNO	12.9%
WEB Grating	WWEB	12.9%
Wellington Street	WWNT	12.9%
Welshpool	WWEL	12.9%
Wembley Downs	WWDN	12.9%
West Kalgoorlie	WWKT	12.9%
Western Collieries	WWCL	12.9%
Western Mining	WWMG	12.9%
Westralian Sands	WWSD	12.9%
Worsley	WWOR	12.9%
Wundowie	WWUN	12.9%
Yanchep	WYCP	12.9%
Yerbillon	WYER	12.9%
Yilgarn	WYLN	12.9%
Yokine	WYKE	12.9%

The % changes in the following table are applicable for reference tariffs: **RT11 & TRT2**.

Table 22

Substation	TNI	Use of System % Change
Albany Windfarm	WALB	12.9%
Boulder	WBLD	12.9%
Cockburn PWS	WCKB	12.9%
Collie PWS	WCPS	12.9%
Emu Downs	WEMD	12.9%
Geraldton GT	WGTN	12.9%
Kemerton PWS	WKEM	12.9%
Kwinana Alcoa	WAKW	12.9%
Kwinana PWS	WKPS	12.9%
Landwehr (Alinta)	WLWT	12.9%

Substation	TNI	Use of System % Change
Mason Road	WMSR	12.9%
Mason Road Hismelt	WHIS	12.9%
Muja PWS	WMPS	12.9%
Mungarra GTs	WMGA	12.9%
Oakley (Alinta)	WOLY	12.9%
Parkeston	WPKS	12.9%
Pinjar GTs	WPJR	12.9%
Alcoa Pinjarra	WAPJ	12.9%
Tiwest GT	WKMK	12.9%
Wagerup Alcoa	WAWG	12.9%
Walkaway Windfarm	WWWF	12.9%
West Kalgoorlie GTs	WWKT	12.9%
Worsley	WWOR	12.9%

9.2 Connection Prices

The % changes in the following table are applicable for reference tariff: **RT11**.

Table 23

	Connection Price % Change
Connection Price	12.9%

9.3 Common Service Prices

The % changes in the following table are applicable for reference tariff: **TRT1**.

Table 24

	Common Service Price % Change
Common Service Price	12.9%

9.4 Metered Demand Prices

The % changes in the following table are applicable for reference tariff: **RT5**.

Table 25

	Transmission		Distribution		Bundled Tariff	
Demand (kVA) (Lower to upper threshold)	Fixed % Change	Demand (in excess of lower threshold) % Change	Fixed % Change	Demand (in excess of lower threshold) % Change	Fixed % Change	Demand (in excess of lower threshold) % Change
0 to 300		12.9%	17.7%	17.7%	17.7%	15.5%
300 to 1000	12.9%	12.9%	17.7%	17.7%	15.6%	15.6%
1000 to 1500	12.9%	12.9%	17.7%	17.6%	15.6%	15.2%

The % changes in the following table are applicable for reference tariff: **RT6**.

Table 26

	Transmission		Distribution		Bundled Tariff	
Demand (kVA) (Lower to upper threshold)	Fixed % Changes	Demand (in excess of lower threshold) % Changes	Fixed % Change	Demand (in excess of lower threshold) % Change	Fixed % Change	Demand (in excess of lower threshold) % Change
0 to 300		12.9%	17.7%	17.7%	17.7%	15.7%
300 to 1000	12.9%	12.9%	17.7%	17.7%	15.8%	15.8%
1000 to 1500	12.9%	12.9%	17.7%	17.7%	15.8%	15.6%

9.5 Demand Prices

The % change in the following table are applicable for reference tariff: **RT7 & RT8**.

Table 27

Zone Substation	TNI	Pricing Zone	Transmission			Distribution			Bundled		
			Fixed charge for first 1000 kVA % Change	Demand charge for 1000<kVA<7000 % Change	Demand Charge for kVA > 7000 % Change	Fixed charge for first 1000 kVA % Change	Demand charge for 1000<kVA<7000 % Change	Demand Charge for kVA > 7000 % Change	Fixed charge for first 1000 kVA % Change	Demand charge for 1000<kVA<7000 % Change	Demand Charge for kVA > 7000 % Change
Cook Street	WCKT	CBD	12.9%	12.9%	12.9%	17.7%	17.7%	17.7%	15.4%	14.2%	14.4%
Forrest Avenue	WFRT	CBD	12.9%	12.9%	12.9%	17.7%	17.7%	17.7%	15.4%	14.2%	14.4%
Hay Street	WHAY	CBD	12.9%	12.9%	12.9%	17.7%	17.7%	17.7%	15.4%	14.2%	14.4%
Milligan Street	WMIL	CBD	12.9%	12.9%	12.9%	17.7%	17.7%	17.7%	15.4%	14.2%	14.4%
Wellington Street	WWNT	CBD	12.9%	12.9%	12.9%	17.7%	17.7%	17.7%	15.4%	14.2%	14.4%
Black Flag	WBKF	Goldfields Mining	12.9%	12.9%	12.9%	17.7%	17.6%	17.6%	15.4%	13.3%	13.6%
Boulder	WBLD	Goldfields Mining	12.9%	12.9%	12.9%	17.7%	17.6%	17.6%	15.4%	13.3%	13.6%
Bounty	WBNY	Goldfields Mining	12.9%	12.9%	12.9%	17.7%	17.6%	17.6%	15.4%	13.1%	13.3%
West Kalgoorlie	WWKT	Goldfields Mining	12.9%	12.9%	12.9%	17.7%	17.6%	17.6%	15.4%	13.3%	13.6%
Albany	WALB	Mixed	12.9%	12.9%	12.9%	17.7%	17.7%	17.7%	15.4%	13.8%	14.0%
Boddington	WBOD	Mixed	12.9%	12.9%	12.9%	17.7%	17.7%	17.7%	15.4%	14.4%	14.6%
Bunbury Harbour	WBUH	Mixed	12.9%	12.9%	12.9%	17.7%	17.7%	17.7%	15.4%	14.4%	14.6%
Busselton	WBSN	Mixed	12.9%	12.9%	12.9%	17.7%	17.7%	17.7%	15.4%	13.9%	14.1%
Byford	WBYF	Mixed	12.9%	12.9%	12.9%	17.7%	17.7%	17.7%	15.4%	14.3%	14.5%
Capel	WCAP	Mixed	12.9%	12.9%	12.9%	17.7%	17.7%	17.7%	15.4%	14.0%	14.3%
Chapman	WCPN	Mixed	12.9%	12.9%	12.9%	17.7%	17.7%	17.7%	15.4%	13.8%	14.0%
Darlington	WDTN	Mixed	12.9%	12.9%	12.9%	17.7%	17.7%	17.7%	15.4%	14.3%	14.5%
Durlacher Street	WDUR	Mixed	12.9%	12.9%	12.9%	17.7%	17.7%	17.7%	15.4%	13.9%	14.1%
Eneabba	WENB	Mixed	12.9%	12.9%	12.9%	17.7%	17.7%	17.7%	15.4%	13.9%	14.1%
Geraldton	WGTN	Mixed	12.9%	12.9%	12.9%	17.7%	17.7%	17.7%	15.4%	13.9%	14.1%
Marriott Road	WMRR	Mixed	12.9%	12.9%	12.9%	17.7%	17.7%	17.7%	15.4%	14.4%	14.6%

Zone Substation	TNI	Pricing Zone	Transmission			Distribution			Bundled		
			Fixed charge for first 1000 kVA % Change	Demand charge for 1000<kVA<7000 % Change	Demand Charge for kVA > 7000 % Change	Fixed charge for first 1000 kVA % Change	Demand charge for 1000<kVA<7000 % Change	Demand Charge for kVA > 7000 % Change	Fixed charge for first 1000 kVA % Change	Demand charge for 1000<kVA<7000 % Change	Demand Charge for kVA > 7000 % Change
Muchea	WMUC	Mixed	12.9%	12.9%	12.9%	17.7%	17.7%	17.7%	15.4%	14.2%	14.4%
Northam	WNOR	Mixed	12.9%	12.9%	12.9%	17.7%	17.7%	17.7%	15.4%	13.9%	14.1%
Picton	WPIC	Mixed	12.9%	12.9%	12.9%	17.7%	17.7%	17.7%	15.4%	14.3%	14.5%
Rangeway	WRAN	Mixed	12.9%	12.9%	12.9%	17.7%	17.7%	17.7%	15.4%	13.9%	14.1%
Sawyers Valley	WSVL	Mixed	12.9%	12.9%	12.9%	17.7%	17.7%	17.7%	15.4%	13.9%	14.1%
Yanchep	WYCP	Mixed	12.9%	12.9%	12.9%	17.7%	17.7%	17.7%	15.4%	14.3%	14.5%
Yilgarn	WYLN	Mixed	12.9%	12.9%	12.9%	17.7%	17.7%	17.7%	15.4%	13.8%	14.1%
Baandee	WBDE	Rural	12.9%	12.9%	12.9%	17.7%	17.8%	17.7%	15.4%	13.3%	13.6%
Beenup	WBNP	Rural	12.9%	12.9%	12.9%	17.7%	17.8%	17.7%	15.4%	13.3%	13.6%
Bridgetown	WBTN	Rural	12.9%	12.9%	12.9%	17.7%	17.8%	17.7%	15.4%	13.5%	13.9%
Carrabin	WCAR	Rural	12.9%	12.9%	12.9%	17.7%	17.8%	17.7%	15.4%	13.3%	13.5%
Collie	WCOE	Rural	12.9%	12.9%	12.9%	17.7%	17.8%	17.7%	15.4%	13.4%	13.7%
Coolup	WCLP	Rural	12.9%	12.9%	12.9%	17.7%	17.8%	17.7%	15.4%	13.4%	13.7%
Cunderdin	WCUN	Rural	12.9%	12.9%	12.9%	17.7%	17.8%	17.7%	15.4%	13.3%	13.6%
Katanning	WKAT	Rural	12.9%	12.9%	12.9%	17.7%	17.8%	17.7%	15.4%	13.4%	13.7%
Kellerberrin	WKEL	Rural	12.9%	12.9%	12.9%	17.7%	17.8%	17.7%	15.4%	13.3%	13.6%
Kojonup	WKOJ	Rural	12.9%	12.9%	12.9%	17.7%	17.8%	17.7%	15.4%	13.6%	14.0%
Kondinin	WKDN	Rural	12.9%	12.9%	12.9%	17.7%	17.8%	17.7%	15.4%	13.5%	13.9%
Manjimup	WMJP	Rural	12.9%	12.9%	12.9%	17.7%	17.8%	17.7%	15.4%	13.5%	13.9%
Margaret River	WMRV	Rural	12.9%	12.9%	12.9%	17.7%	17.8%	17.7%	15.4%	13.3%	13.6%
Merredin	WMER	Rural	12.9%	12.9%	12.9%	17.7%	17.8%	17.7%	15.4%	13.4%	13.6%
Moora	WMOR	Rural	12.9%	12.9%	12.9%	17.7%	17.8%	17.7%	15.4%	13.5%	13.8%
Mount Barker	WMBR	Rural	12.9%	12.9%	12.9%	17.7%	17.8%	17.7%	15.4%	13.4%	13.7%
Narrogin	WNGN	Rural	12.9%	12.9%	12.9%	17.7%	17.8%	17.7%	15.4%	13.3%	13.6%
Pinjarra	WPNJ	Rural	12.9%	12.9%	12.9%	17.7%	17.8%	17.7%	15.4%	13.7%	14.1%
Regans	WRGN	Rural	12.9%	12.9%	12.9%	17.7%	17.8%	17.7%	15.4%	13.5%	13.8%
Three Springs	WTSG	Rural	12.9%	12.9%	12.9%	17.7%	17.8%	17.7%	15.4%	13.5%	13.8%
Wagerup	WWGP	Rural	12.9%	12.9%	12.9%	17.7%	17.8%	17.7%	15.4%	13.8%	14.2%
Wagin	WWAG	Rural	12.9%	12.9%	12.9%	17.7%	17.8%	17.7%	15.4%	13.4%	13.7%
Wundowie	WWUN	Rural	12.9%	12.9%	12.9%	17.7%	17.8%	17.7%	15.4%	13.4%	13.7%
Yerbillon	WYER	Rural	12.9%	12.9%	12.9%	17.7%	17.8%	17.7%	15.4%	13.3%	13.5%
Amherst	WAMT	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Arkana	WARK	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Australian Paper Mills	WAPM	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Beechboro	WBCH	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Belmont	WBEL	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Bentley	WBTY	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Bibra Lake	WBIB	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
British Petroleum	WBPM	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Canning Vale	WCVE	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Clarence Street	WCLN	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%

Zone Substation	TNI	Pricing Zone	Transmission			Distribution			Bundled		
			Fixed charge for first 1000 kVA % Change	Demand charge for 1000<kVA<7000 % Change	Demand Charge for kVA > 7000 % Change	Fixed charge for first 1000 kVA % Change	Demand charge for 1000<kVA<7000 % Change	Demand Charge for kVA > 7000 % Change	Fixed charge for first 1000 kVA % Change	Demand charge for 1000<kVA<7000 % Change	Demand Charge for kVA > 7000 % Change
Clarkson	WCKN	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Cockburn Cement	WCCT	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Collier	WCOL	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Cottesloe	WCOT	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Edmund Street	WEDD	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Forrestfield	WFFD	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Gosnells	WGNL	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Hadfields	WHFS	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Hazelmere	WHZM	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Henley Brook	WHBK	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Herdsman Parade	WHEP	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Joel Terrace	WJTE	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Joondalup	WJDP	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Joondanna	WJDA	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Kalamunda	WKDA	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Kambalda	WKBA	Urban	12.9%	12.9%	12.9%	17.7%	17.6%	17.7%	15.4%	13.0%	13.4%
Landsdale	WLDE	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Malaga	WMLG	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Mandurah	WMHA	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Manning Street	WMAG	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Mason Road	WMSR	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Meadow Springs	WMSS	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Medical Centre	WMCR	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Medina	WMED	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Midland Junction	WMJX	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Morley	WMOY	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Mullaloo	WMUL	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Mundaring Weir	WMWR	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Murdoch	WMUR	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Myaree	WMYR	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Nedlands	WNED	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
North Beach	WNBH	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
North Fremantle	WNFL	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
North Perth	WNPH	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
OConnor	WOCN	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Osborne Park	WOPK	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Padbury	WPBY	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Piccadilly	WPCY	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Riverton	WRTN	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Rivervale	WRVE	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%

Zone Substation	TNI	Pricing Zone	Transmission: Fixed charge for first 1000 kVA % Change	Transmission: Demand charge for 1000<kVA<7000 % Change	Transmission: Demand Charge for kVA > 7000 % Change	Distribution: Fixed charge for first 1000 kVA % Change	Distribution: Demand charge for 1000<kVA<7000 % Change	Distribution: Demand Charge for kVA > 7000 % Change	Bundled: Fixed charge for first 1000 kVA % Change	Bundled: Demand charge for 1000<kVA<7000 % Change	Bundled: Demand Charge for kVA > 7000 % Change
Rockingham	WROH	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Shenton Park	WSPA	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Sth Ftle Power Station	WSFT	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Southern River	WSNR	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Tate Street	WTTS	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
University	WUNI	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Victoria Park	WVPA	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Waikiki	WWAI	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Wanneroo	WWNO	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Welshpool	WWEL	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Wembley Downs	WWDN	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Willeton	WWLN	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%
Yokine	WYKE	Urban	12.9%	12.8%	12.8%	17.7%	17.6%	17.7%	15.4%	13.1%	13.7%

9.6 Demand Length Prices

The % changes in the following table are applicable for reference tariffs: **RT5, RT6, RT7, RT8 & RT11** and the CMD/DSOC is between 1,000 and 7,000 kVA.

Table 28

Pricing Zone	Demand-Length Charge: For kVA >1000 and first 10 km length % Change	Demand-Length Charge: For kVA >1000 and length in excess of 10 km % Change
CBD	N/A	N/A
Urban	17.7%	17.9%
Mining	17.4%	17.7%
Mixed	17.8%	17.8%
Rural	17.9%	17.9%

The % changes in the following table are applicable for reference tariffs: **RT7, RT8 & RT11** and the CMD/DSOC is at least 7,000 kVA.

Table 29

Pricing Zone	Demand-Length Charge: For first 10 km length % Change	Demand-Length Charge: For length in excess of 10 km % Change
CBD	N/A	N/A
Urban	17.7%	17.9%

Mining	17.6%	17.1%
Mixed	17.6%	18.0%
Rural	18.0%	17.7%

9.7 Control System Service Prices

The % changes in the following table are applicable for reference tariff: **RT11, & TRT2**.

Table 30

	Price % Change
Control System Service Price (Generators)	12.9%

The % changes in the following table are applicable for reference tariff: **TRT1**.

Table 31

	Price % Change
Control System Service Price (Loads)	12.9%

9.8 Metering Prices

The % changes in the following table are applicable for reference tariffs: **RT1, RT2, RT3 & RT4**.

Table 32

	Fixed Price	Variable Price		
	% Change	Anytime % Change	On Peak % Change	Off Peak % Change
Reference tariff 1 - RT1				
Metering Price	17.7%	17.7%	-	-
Reference tariff 2 - RT2				
Metering Price	17.7%	17.7%	-	-
Reference tariff 3 - RT3				
Metering Price	17.7%	-	17.7%	17.7%
Reference tariff 4 - RT4				
Metering Price	17.7%	-	17.4%	17.4%

The % changes in the following table are applicable for reference tariffs: **RT5, RT6, RT7, RT8 & RT11**.

Table 33

Metering Equipment Funding	Voltage	% Change
Western Power funded	High Voltage (6.6 kV or higher)	17.7%

	Low voltage (415 volts or less)	17.7%
Customer funded	High Voltage (6.6 kV or higher)	17.7%
	Low Voltage (415 volts or less)	17.7%

The % changes in the following table are applicable for reference tariffs: **TRT1 & TRT2**.

Table 34

	% Change
Transmission Metering	12.9%

9.9 Administration Prices

The % changes in the following table are applicable for reference tariffs: **RT7 & RT8**.

Table 35

Peak Demand	% Change
>=7,000 kVA	17.7%
<7,000 kVA	17.6%

9.10 Low Voltage Prices

The % changes in the following table are applicable for reference tariff: **RT8**.

Table 36

Category	% Change
Fixed	17.7%
Demand	17.7%

9.11 Streetlight Asset Prices

The % changes in the following table are applicable for reference tariff: **RT9**.

Table 37

Light Specification	Annual Charge % Change
50W MV	17.7%
70W MH	17.7%
70W HPS	17.7%
80W MV	17.7%
125W MV	17.6%
150W MH	17.7%
150W HPS	17.7%
250W MH	17.7%

250W HPS	17.7%
250W MV	17.7%
400W MV	17.7%

Appendix A - Price Setting for New Transmission Nodes Policy

This policy applies when a new transmission node is established.

Transmission "use of system" prices for both entry and exit points are derived using the computer based analysis tool T-Price, based on historical load flow information. In the case of new sites, historical data is not available.

However, there is a need for both Western Power and the prospective user to have a fairly accurate TUOS price and connection price. Western Power requires the prices to determine future revenues from the connection, and any associated capital contribution. The user requires the price and capital contribution for the purposes of project feasibility, and their internal approval processes.

This policy addresses this issue by providing a degree of price certainty over the medium term.

Policy Statement – Transmission Use of System Price (TUOS)

This policy will apply to new connection points on the transmission and distribution system where the prospect is that it will be a single connection point.

1. Western Power will nominate a TUOS price consistent with all the principles described in this document based on the best available knowledge of the network parameters including asset values and expected load flows. This would also include necessary assumptions for maximum demand and utilisation at the new connection and also any other new or forecast connections.

2. That nominated nodal TUOS price will then be adjusted annually in line with the average TUOS price adjustment for all transmission nodes.

3. Once that connection point is established the nominated TUOS price (adjusted in accordance with step 2) will apply at the commencement of the access contract, with annual price adjustments at the start of each financial year of no greater than (plus or minus) the annual pricing side constraint as detailed in the Access Arrangement. (Thus, the nominated TUOS price will converge over time with and future price based on future T-Price runs.)

4. The TUOS price will be published once the connection point is commissioned.

5. Where another user subsequently connects to such a connection point the price that will apply will be the price applying to that connection point at the time.

6. The common service, metering and control system prices that apply in this circumstance will be the standard published prices.

Policy Statement – Transmission Connection Price

The transmission connection price, for new connections where there was no previous connection point, is determined in accordance with the principles described below. There are two categories in which the new connection point can fit.

A connection that is unlikely to be shared by other users.

In this case the connection asset would be dedicated to the single user. The asset can be constructed either by the user or by Western Power, and the user has the option to own the asset or to allow Western Power to own the asset.

Where Western Power will own the asset the capital contribution for the connection asset will be as determined by the Contributions Policy.

The annual connection price is calculated to recover to expected operations and maintenance costs for the connection asset and is currently set at 2.1% of the full capital cost. This percentage is based on the ratio of the Operations and Maintenance cost and the GODV of the transmission network. Once the annual connection price has been determined for a particular connection point, the price is adjusted annually by the all capitals consumer price index (CPI).

A connection point where there is a high likelihood that other users will connect in the future.

In this circumstance the user still retains the option of owning the connection asset. If the user prefers this option Western Power may require the ability to build connection assets for other users on the same site. Where the user does select this option the calculation of the capital contribution and the associated connection access price is on the same basis as the first option.

Where the user would prefer Western Power to own the connection asset, the connection access price would be the published price that applies to all multi-user substations within the SWIS. This published price would be used by Western Power to calculate the capital contribution for the connection asset.

Western Power will offer this option at its discretion depending on the likelihood of future users connecting to the connection point.