Determination on the Proposed 2012/13 Price List for Western Power's Covered Electricity Network

Submitted by Western Power

May 2012

Economic Regulation Authority
WESTERN AUSTRALIA

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Economic Regulation Authority web site at www.erawa.com.au.

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Contents

DETERMINATION

1. On 27 April 2012, Western Power submitted a proposed 2012/13 price list (**2012/13 price list**) for the Western Power Network to the Economic Regulation Authority (**Authority**) for the Authority's approval under Chapter 8 of the *Electricity Networks Access Code 2004* (**Access Code**).[1]

2. Western Power has submitted its proposed 2012/13 price list under the current access arrangement that applies to the Western Power Network that commenced on 1 March 2010.[2] While Western Power has submitted proposed revisions to the current access arrangement to the Authority with the intention for the revisions to have effect from 1 July 2012, the Authority has not yet made a final decision on those proposed revisions. In these circumstances, the current access arrangement will continue to have effect until a final decision is made. As a result, the proposed 2012/13 price list must comply with relevant terms of the current access arrangement.[3]

3. The Authority has assessed the proposed 2012/13 price list and considers that it does not comply with both the price control and pricing methods of the current access arrangement.

4. The Authority observes that section 6 of Western Power's proposed 2012/13 price list contains a list of fees referred to as non-reference service tariffs. This Determination does not apply to those stated fees/tariffs, as the Authority is not required to assess or approve such fees/tariffs as part of its price list determination.

5. In accordance with section 8.3 of the Access Code, the Authority does not approve the proposed 2012/13 price list. The Authority's reasons are set out below.

REASONS FOR DETERMINATION

Requirements of the Access Code

6. Chapter 8 of the Access Code sets out requirements for a service provider to submit proposed price lists, and for the Authority to approve and publish the proposed price lists and related price list information.

Approval of price lists if required

8.1 If a service provider's access arrangement requires it to submit price lists to the Authority for approval, the service provider must, at least 45 business days before the start of each pricing year (except for the first pricing year), submit to the Authority:

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[1] Western Power, 27 April 2012, 2012/13 Price List and 2012/13 Price List Information.

[2] Western Power, 24 December 2009, Amended Proposed Access Arrangement for the South West Interconnected Network owned by Western Power (hereafter cited as **"current access arrangement"**).

[3] The current access arrangement was approved by the Authority on 19 January 2010 with a commencement date of 1 March 2010. Under the Access Code, this current version of the access arrangement continues in effect until proposed revisions that have been assessed and approved by the Authority come into effect. Western Power submitted proposed revisions to its access arrangement on 30 September 2011, with a target revisions commencement date of 1 July 2012. Based on current timelines, the assessment process will not be completed until sometime after 1 July 2012.

(a) a proposed price list to apply for the next pricing year; and

(b) price list information.

8.2 If the Authority considers that a service provider's proposed price list complies with:

(a) the price control in the service provider's access arrangement; and

(b) the pricing methods in the service provider's access arrangement,

then the Authority must:

(c) approve and publish the service provider's proposed price list which has effect from a date specified by the Authority; and

(d) publish the service provider's price list information.

8.3 The Authority must not approve a service provider's proposed price list if the proposed price list does not comply with sections 8.2(a) and 8.2(b), and must notify the service provider that it does not approve the proposed price list and provide reasons.

8.4 If a service provider is notified under section 8.3 that the Authority does not approve a proposed price list submitted by the service provider, the service provider may at any time submit a revised proposed price list to the Authority.

8.5 If the Authority:

(a) notifies a service provider under section 8.3 that it does not approve a proposed price list submitted by the service provider; and

(b) has not approved a revised proposed price list,

then the price list most recently in effect continues in effect until the Authority approves a revised proposed price list submitted by the service provider under section 8.4.

8.6 If the Authority has not notified a service provider that it does not approve a proposed price list within 15 business days after receiving either:

(a) the proposed price list; or

(b) any further information the Authority has requested in relation to the proposed price list,

(whichever is later), then the Authority is to be taken to have approved the price list.

Publication of price lists if approval not required

8.7 If a service provider's access arrangement does not require it to submit price lists to the Authority for approval, the service provider must, at least 25 business days before the start of each pricing year (except for the first pricing year), submit to the Authority a copy of:

(a) a price list to apply in respect of the next pricing year which complies with:

(i) the price control in the service provider's access arrangement; and

(ii) the pricing methods in the service provider's access arrangement;

and

(b) price list information.

8.8 Where a service provider submits a price list and price list information to the Authority under section 8.7, the Authority must publish the price list and price list information.

Submission of the Proposed Price List

7. Clause 3.10 of Western Power's current access arrangement requires it to submit to the Authority a proposed price list, together with price list information, at least 45 business days before the start of each pricing year (except for the first pricing year).

8. On 27 April 2012, Western Power submitted a proposed 2012/13 price list and price list information to the Authority. Western Power also provided to the Authority confidential spreadsheets containing additional supporting information and calculations to indicate the forecast of revenue associated with the proposed 2012/13 price list.

Compliance of the Proposed Price List with the Price Control

Specification of the Price Control under the Current Access Arrangement

9. Under the Access Code, "price control" refers to the provisions of an access arrangement that determine the target revenue to be earned by the service provider, enable users to predict likely annual changes in target revenue during the access arrangement period, and aim to avoid price shocks (material tariff adjustments between succeeding years).

10. Clauses 5.25 to 5.48A of the current access arrangement establish revenue cap price controls for each of the transmission and distribution networks. The operation of these price controls within an access arrangement period is set out in clauses 5.35 to 5.37A and 5.46 to 5.48A of the current access arrangement (see extract of relevant clauses in Appendix 1).

11. Related to the price control is a "side constraint" that limits the extent to which component charges of reference tariffs may be increased or decreased from one pricing year of the access arrangement period to the next. Clauses 3.10A and 3.11 of the current access arrangement establishes side constraints on price changes that allows reference tariff charges to change by a factor of plus or minus (+/-):

- "CPI + 13 percentage points for the transmission network"; and
- "CPI + 18 percentage points for the distribution network".[4]

Revenue Cap and Side Constraint for 2012/13

12. The Authority must not approve the proposed 2012/13 price list if it does not comply with both the price control and the pricing methods in the current access arrangement (section 8.3 of the Access Code). There are some difficulties in assessing whether the pricing methodology complies with the current access arrangement where a revenue cap form of price control applies because the current access arrangement does not contain amounts required to calculate the transmission and distribution network revenue caps for references services for periods beyond 30 June 2012.

13. In particular, clauses 5.35 and 5.46 of the current access arrangement provide for the TR_t (transmission revenue for the transmission network) and the DR_t

[4] The actual side constraint is plus or minus (+/-) the total of the percentage change in the CPI, plus 13 or 18 percentage points for the transmission or distribution network respectively. The CPI is the CPI (weighted average for eight capital cities) for the most recent December quarter compared to the December quarter in the previous year.

(distribution revenue for the distribution network) values in the pricing methodologies to be based on the forecast transmission and distribution reference service revenues for the relevant years. There are no such values specified beyond 30 June 2012. The Access Code does not otherwise prescribe the relevant values to be used in the pricing methodologies in these circumstances. A literal interpretation of section 8.2(b) of the Access Code would suggest the target revenues (subject to any applicable escalation provisions) as stated in the current access arrangement would need to be applied. However, as reference tariffs are intended to "recover forward-looking efficient costs" (section 7.3(a) of the Access Code), the use of target revenues that applied in previous pricing years, where the form of price control is "revenue cap", is unlikely to be consistent with the objective in section 7.3(a) of the Access Code. There is a further difficulty with the amount of the tariff equalisation contribution as explained below.

14. In the absence of an approved revenue cap for 2012/13 under the current access arrangement, Western Power has calculated revenue caps based on the Authority's draft decision in relation to the proposed revised access arrangement for the third access arrangement period.

15. The Authority notes that a number of factors may lead to these figures being revised in its final decision, including the information provided with Western Power's proposed 2012/13 Price List in relation to updated demand forecasts. Consequently, the Authority is concerned with the appropriateness of using revenue targets from the draft decision and, in any case, those revenue targets are not specified in the current access arrangement.

Correction Factor

16. Correction factors have been calculated from required and collected revenues from previous pricing years. The correction factors were derived by applying a weighted average cost of capital (WACC) of 7.98 per cent, as approved in the current access arrangement.

17. The correction factors include adjustments for the 2010/11 and 2011/12 financial years. The adjustment in financial year 2010/11 is supported by the actual revenue figures reported in the Regulatory Accounts. However, the 2011/12 correction is based on a revised forecast for the 2011/12 financial year compared with the forecast made at the time the 2011/12 price list was prepared. This revised forecast was not indicated in Western Power's proposed revisions to the access arrangement for the third access arrangement period. In response to queries in relation to the proposed price list, Western Power has provided copies of its quarterly supplementary information packs. Whilst these reports indicate that revenue for the 2011/12 year is likely to be below the original forecast, the March 2012 quarterly report indicates the variance is less than was anticipated in December 2011. The monthly energy statistics included in the March quarterly report appear to indicate that, although energy volumes were lower than forecast initially, actual volumes have been higher than forecast for the months since November 2011.The Authority considers that Western Power has not provided sufficient evidence to support the level of reduction in forecast revenue for 2011/12.

Tariff Equalisation Contribution (TEC)

18. In determining a value of required distribution revenue, Western Power has included an amount of $166.2 million ($ June 2009) as a tariff equalisation contribution (TEC_t) for 2012/13.

19. A TEC has not been gazetted by the Treasurer for the period commencing on 1 July 2012 and ending on 30 June 2013. As a result, the TEC proposed by Western Power does not comply with section 6.37A of the Access Code.

Inflation Factor

20. Western Power indicates in section 1.4.3 of the price list information that the inflation factor, used to calculate the required revenue from reference services in nominal dollar values, is derived from actual inflation for the annual period March 2009 to March 2010 (2.89 per cent) and March 2010 to March 2011 (3.33 per cent). Forecasts of inflation for the annual periods March 2011 to March 2012 (2.50 per cent) and March 2012 to March 2013 (3.00 per cent) have been used. The Authority notes that the Australian Bureau of Statistics released actual inflation data for the March 2012 quarter of 1.6 per cent.[5] This is materially lower than the 2.5 per cent assumed by Western Power. Having regard to the discrepancy in the inflation index assumed for 2012, the Authority considers Western Power's forecast for 2013 is inappropriate.

Forecast Revenue 2012/13

21. Spreadsheets provided by Western Power to the Authority (on a confidential basis) comprise calculations of the expected revenue to be collected from the component charges of reference tariffs as set out in the proposed 2012/13 price list, given forecasts of demand for each charge.[6]

22. The Authority notes that the forecasts of demand are significantly reduced from the forecasts provided with Western Power's proposal for the third access arrangement period. Further analysis is required to substantiate the revised forecasts. Expenditure forecasts for the third access arrangement period will also need to be reviewed in light of any revisions to the demand forecasts. Any revisions to expenditure will impact on the assessment of the revenue cap for the 2012/13 year.

Side Constraint

23. Clause 3.11 of the current access arrangement sets out the side constraint that applies to increases in network charges:

- +/- (CPI + 13 percentage points) for the transmission network; and
- +/- (CPI + 18 percentage points) for the distribution network,

with CPI being the percentage increase in the CPI (weighted average for eight capital cities) for the most recent December quarter compared to the December quarter in the previous year.

24. Section 9 of the price list information submitted by Western Power indicates the percentage changes in charges between the 2011/12 price list and the proposed 2012/13 price list. The percentage changes are within the current side constraints and comprise:

- increases in charges for transmission reference tariffs of 0 per cent; and

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5 Australian Bureau of Statistics, 6401.0 – Consumer Price Index, Australia, March 2012 (released 24/04/12)

6 Western Power, 27 April 2012, 2012/13 Price List Information (and confidential revenue spreadsheets for transmission and distribution)

- increases in charges for distribution reference tariffs of 13 per cent.

Conclusion

25. On the basis of the concerns expressed above the Authority does not consider that the proposed 2012/13 price list complies with the price control in the current access arrangement (section 8.2 of the Access Code). The proposed 2012/13 price list does not comply with the current access arrangement for the following reasons:

    - revenue caps from the AA3 draft decision are not specified in the current access arrangement and are under review;
    - a TEC has not been gazetted for the relevant period;
    - the inflation rate used is inappropriate;
    - changes in demand forecast for 2012/13 compared with the AA3 submission are not adequately substantiated and will in any case need to be considered as part of the final decision in relation to the revenue cap for the 2012/13 year; and.
    - the level of reduction in the revenue forecast for 2011/12 is not adequately substantiated.

Compliance of the Price List with the Pricing Methods

26. "Pricing methods" under the Access Code refer to the structure of reference tariffs included in the access arrangement, which determines how the maximum revenue is allocated across and within reference services.

27. Clauses 9.1 to 9.30 of the current access arrangement detail the pricing methods applied by Western Power. The pricing method is designed to achieve the objectives set out in sections 7.3 and 7.4 of the Access Code.

28. Section 7.3(b) of the Access Code requires reference tariffs to be between the incremental and stand-alone cost of service provision. However, in its Price List Information, Western Power notes that it has not attempted to quantitatively demonstrate that the Price List complies with section 7.3(b) of the Access Code. The reason given by Western Power is that it is difficult to do so absent there being approved costs to serve as a basis for setting revenues and prices for 2012/13.

29. Western Power asserts, however, that the proposed 2012/13 price list complies with the cost allocations of the pricing methods on the basis there have been no changes to the structure of reference tariffs or the relativities of reference tariff charges in deriving the proposed price list for 2011/12 which complied with section 7.3(b) of the Access Code.[7]

30. The Authority notes that Western Power's proposal for the third access arrangement period indicates that, after many years of flat scaled increases, adjustments were required to set all prices to their cost reflective levels. The Authority considers that this has not been taken into account in the proposed 2012/13 price list. Instead, Western Power has continued to apply flat scaled increases.

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[7] Price list information, pp. 54, 55.

31. The Authority considers that Western Power has not adequately demonstrated compliance with the pricing methods objectives in sections 7.3 and 7.4 of the Access Code.

Appendix 1 Specification of the Price Control under the Amended Access Arrangement

The following extracts from Western Power's amended access arrangements set out the price controls within the access arrangement period.

5.35 For this access arrangement period, the maximum transmission reference service revenue MTR_t is determined as follows:

$$MTR_t = TR_t + AA\#1_t + TK_t$$

Where:

TR_t is the dollar amount in money of the day terms (current prices) for the financial

year t calculated from the dollar amounts (expressed in 30 June 2009 prices) set out in the table below.

Transmission reference service revenues to be used for calculating TR_t ($ million real as at 30 June 2009)

	2009/10	2010/11	2011/12
TR_t	262.90	332.05	384.34

TK_t is the correction factor calculated in accordance with sections 5.36 and 5.37 of this Access Arrangement, which takes account of any difference between the maximum transmission reference service revenue in financial year t-1 and the actual transmission reference service revenue in financial year t-1.

$AA\#1_t$ is a positive or negative smoothed amount for the financial year *t* calculated to give effect to the following adjustments (if applicable) in accordance with the previous access arrangement:

- Adjusting target revenue for unforeseen events;
- Adjusting target revenue for technical rule changes;
- Investment adjustment mechanism; and
- Capital contributions adjustment mechanism.

For the avoidance of doubt, $AA\#1_t$ must take account of inflation, the time value of money and estimates (if any) of the above adjustments that have been included in the calculation of TR_t in this section 5.35 of this Access Arrangement. Western Power will provide model outputs to the Authority to demonstrate that the above smoothed adjustments have been made in accordance with the previous access arrangement.

For the purpose of determining compliance with this revenue cap and calculating TR_t, TK_t and therefore MTR_t, in each financial year CPI adjustments will be effected by using published CPI data relating to the relevant March quarters.

5.36 For financial years commencing on 1 July 2010 and 1 July 2011:

$TK_t = (MTR_{t-1} - ATR_{t-1}) * (1+WACC_{pre\text{-}tax\ real})$

Where:

MTR_{t-1} is the maximum reference service revenue for Western Power's transmission network in the previous financial year.

ATR_{t-1} is the actual transmission reference service revenue in the previous financial year as defined in accordance with section 5.29 of this Access Arrangement.

$WACC_{pre\text{-}tax\ real}$ is 7.98%.

For the financial year commencing on 1 July 2009, TK_t, will be calculated in accordance with the previous access arrangement.

For the avoidance of doubt, it should be noted that the annual tariff-setting process for financial year *t* typically takes place before the end of financial year t-1. Therefore, TK_t will need to be estimated in the first instance, and then recalculated in the subsequent financial year when ATR_{t-1} is known.

5.37 The correction factor, TK_t, will also apply in the first year of the next access arrangement period to adjust for any difference between maximum transmission reference service revenue and actual transmission reference service revenue, in relation to the financial year commencing on 1 July 2011.

5.37A To manage the overall price increases in this access arrangement period, Western Power has deferred the recovery of some transmission reference service revenue from this access arrangement period to the third or subsequent access arrangement periods. The deferred amount of revenue is $64.5 million ($ real as at 30 June 2009) expressed in present value terms as at 30 June 2009. An amount must be added to the target revenue for the transmission network in the third access arrangement period or subsequent access arrangement periods such that the present value (at 30 June 2009) of the total amount added to target revenue (taking account of inflation and the time value of money) is equal to the present value of the deferred transmission reference service revenue (at 30 June 2009). For the avoidance of doubt, the addition to target revenue in the third and subsequent access arrangement periods must leave Western Power financially neutral compared to a situation where transmission reference service revenue deferral had not occurred. The timeframe for recovering deferred revenue will consider the price impact on users of reference services and will be subject to approval by the Authority.

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5.46 For this access arrangement period, the maximum regulated distribution revenue MDR_t is determined as follows:

$MDR_t = DR_t + TEC_t + AA\#1_t + DK_t$

Where:

DR_t is the dollar amount in money of the day terms (current prices) for the financial year t calculated from the dollar amounts (expressed in 30 June 2009 prices) set out in the table below.

Distribution reference service revenues to be used for calculating DRt ($ million real as at 30 June 2009)

	2009/10	2010/11	2011/12
DR_t	389.01	510.49	646.77

TEC_t is any cost incurred by the distribution network for the financial year *t* as a result of the tariff equalisation contribution in accordance with section 6.37A of the Code. $AA\#1_t$ is a positive or negative smoothed amount for the financial year *t* calculated to give effect to the following adjustments (if applicable) in accordance with the previous access arrangement:

- Adjusting target revenue for unforeseen events;
- Adjusting target revenue for technical rule changes;
- Investment adjustment mechanism; and
- Capital contributions adjustment mechanism.

For the avoidance of doubt, $AA\#1_t$ must take account of inflation, the time value of money and estimates (if any) of the above adjustments that have been included in the calculation of DRt in this section 5.46 of this Access Arrangement. Western Power will provide model outputs to the Authority to demonstrate that the above smoothed adjustments have been made in accordance with the previous access arrangement.

DK_t is the correction factor calculated in accordance with sections 5.47 and 5.48 of this Access Arrangement, which takes account of any difference between the maximum regulated distribution network revenue in financial year t-1 and the actual regulated distribution network revenue in financial year t-1.

For the purpose of determining compliance with this revenue cap and calculating DR_t, DK_t and therefore MDR_t, in each financial year CPI adjustments will be effected by using published CPI data relating to the relevant March quarters.

5.47 For financial years commencing on 1 July 2010 and 1 July 2011:

$$DK_t = (MDR_{t-1} - ADR_{t-1}) * (1+WACC_{\text{pre-tax real}})$$

Where:

MDR_{t-1} is the maximum regulated revenue for Western Power's distribution network in the previous financial year.

ADR_{t-1} is the actual regulated distribution revenue in the previous financial year as defined in accordance with section 5.40 of this Access Arrangement.

$WACC_{\text{pre-tax real}}$ is 7.98%.

For the financial year commencing on 1 July 2009, DK_t will be calculated in accordance with the previous access arrangement.

For the avoidance of doubt, it should be noted that the annual tariff-setting process for financial year t typically takes place before the end of financial year t-1. Therefore, DK_t will need to be estimated in the first instance, and then recalculated in the subsequent financial year when ADR_{t-1} is known.

5.48 The correction factor, DK_t, will also apply in the first year of the next access arrangement period to adjust for any difference between maximum distribution reference service revenue and actual distribution reference service revenue, in relation to the financial year commencing on 1 July 2011.

5.48A To manage the overall price increases in this access arrangement period, Western Power has deferred the recovery of some distribution reference service revenue from this access arrangement period to the third or subsequent access arrangement periods. The deferred amount of revenue is $484.2 million ($ real as at 30 June 2009) expressed in present value terms as at 30 June 2009. An amount must be added to the target revenue for the distribution network in the third access arrangement period or subsequent access arrangement periods such that the present value (at 30 June 2009) of the total amount added to target revenue (taking account of inflation and the time value of money) is equal to the present value of the deferred distribution reference service revenue (at 30 June 2009). For the avoidance of doubt, the addition to target revenue in the third and subsequent access arrangement periods must leave Western Power financially neutral compared to a situation where revenue deferral had not occurred. The timeframe for recovering deferred revenue will consider the price impact on users of reference services and will be subject to approval by the Authority.

Appendix 2 Western Power’s Proposed Price List

2012/13 Price List

ELECTRICITY NETWORKS CORPORATION ("WESTERN POWER")

ABN 18 540 492 861

Date of Issue: 27 April 2012
Date of Application 1 July 2012

All prices quoted in this Price List are *GST exclusive.*

DM#9145257

Table of contents

1 INTRODUCTION

This document details Western Power's Price List. For the purpose of section 5.1(f) of the *Electricity Networks Access Code 2004* this document forms part of Western Power's Access Arrangement.

This Price List is for the pricing year commencing on 1 July 2012 and ending on 30 June 2013 or the commencement of the third Access Arrangement regulatory period, whichever is sooner.

For the avoidance of doubt, the prices within this Price List will apply to all consumption during the pricing year. Where consumption is metered with an accumulation meter and the meter reading interval causes some of the metered consumption to lie within the pricing year covered by this price list and the remainder within a previous or subsequent pricing year not covered by this price list, the consumption covered by this price list will be determined by prorating the metered consumption uniformly on a daily basis.

Section 2 lists the reference tariffs for the reference services provided by Western Power as stated in the company's access arrangement.

Sections 3 and 4 detail the reference tariffs, which are based on a number of components. The total charge payable by users under each reference tariff represents the sum of the amounts payable for each component within the relevant reference tariff.

Section 5 details all of the prices that are required to calculate the charges.

Included in section 6 are fees that are referred to in the Applications and Queuing Policy and the Standard Access Contract. Western Power treats these as non-reference services but notes that the list of non-reference service tariffs included in section 6 does not include tariffs for all non-reference services provided by Western Power.

2 REFERENCE SERVICES

The following table details which reference tariff is applicable to each of the 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 (Residential) Bidirectional Service	RT12

3 DISTRIBUTION TARIFF APPLICATION GUIDE

Within this price list the transmission and distribution components of the bundled charges are published, where applicable. The bundled charge is applicable when calculating the charge for the reference tariff, unless otherwise indicated.

For the avoidance of doubt, the bundled charge is the sum of the distribution and transmission components of the charge.

3.1 Reference Tariffs 1 and 2 (RT1 and RT2)

RT1 and RT2 consist of:

(a) a fixed use of system charge (detailed in Table 1) which is payable each day;

(b) a variable use of system charge calculated by multiplying the energy price (detailed in Table 1) by the quantity of electricity consumed at an exit point (expressed in kWh);

(c) a fixed metering charge per revenue meter (detailed in Table 1) which is payable each day; and

(d) a variable metering charge calculated by multiplying the variable price (detailed in Table 1) by the quantity of electricity consumed at an exit point (expressed in kWh).

3.2 Reference Tariffs 3 and 4 (RT3 and RT4)

RT3 and RT4 consist of:

(a) a fixed use of system charge (detailed in Table 1) which is payable each day;

(b) an on-peak use of system variable charge calculated by multiplying the on-peak energy price (detailed in Table 1) by the quantity of on-peak electricity consumed at an exit point (expressed in kWh);

(c) an off-peak use of system variable charge calculated by multiplying the off-peak energy price (detailed in Table 1) by the quantity of off-peak electricity consumed at an exit point (expressed in kWh);

(d) a fixed metering charge per revenue meter (detailed in Table 1) which is payable each day;

(e) an on-peak variable metering charge calculated by multiplying the on-peak variable price (detailed in Table 1) by the quantity of on-peak electricity consumed at an exit point (expressed in kWh); and

(f) an off-peak variable metering charge calculated by multiplying the off-peak variable price (detailed in Table 1) by the quantity of off-peak electricity consumed at an exit point (expressed in kWh).

Notes:

1. The on and off peak periods for these tariffs are defined in the following table (all times are Western Standard Time (WST)):

	Monday – Friday (includes public holidays)			Saturday - Sunday
	Off-peak	**On-Peak**	**Off-Peak**	**Off-Peak**
RT3	12:00am – 7:00am	7:00am – 9:00pm	9:00pm – 12:00am	All times
RT4	12:00am – 8:00am	8:00am – 10:00pm	10:00pm – 12:00am	All times

3.3 Reference Tariff 5 (RT5)

3.3.1 Tariff Calculation

RT5 consists of:

(a) a fixed metered demand charge (detailed in Table 3) which is payable each day based on the rolling 12-month maximum half-hourly demand at an exit point (expressed in kVA) multiplied by (1-Discount);

(b) a variable metered demand charge calculated by multiplying the demand price (in excess of the lower threshold and detailed in Table 3) by the rolling 12-month maximum half-hourly demand at an exit point (expressed in kVA) minus the lower threshold with the result multiplied by (1-Discount);

(c) if the metered demand is greater than 1,000 kVA a variable demand length charge calculated by multiplying the demand length price (detailed in Table 6) by the electrical distance to the zone substation by the rolling 12-month maximum half-hourly demand (expressed in kVA) minus 1,000 kVA (Note: a different rate applies after 10 km); and

(d) a fixed metering charge per revenue meter (detailed in Table 8) which is payable each day.

Notes:

1. The on and off peak periods for this tariff are defined in the following table (all times are Western Standard Time (WST)):

Monday – Friday (includes public holidays)			Saturday - Sunday
Off-peak	**On-Peak**	**Off-Peak**	**Off-Peak**
12:00am – 8:00am	8:00am – 10:00pm	10:00pm – 12:00am	All times

3.3.2 Discount Factor

A discount, based on the percentage of off peak energy consumption (as a proportion of the total energy consumption), applies to this tariff.

The Discount is defined as:

For MD < 1,000 kVA	$(E_{Off\ Peak}/E_{Total}) * DF$
For 1,000 <= MD <1,500 kVA	$((1500 - MD)/500) * (E_{Off\ Peak}/E_{Total}) * DF$
For MD => 1,500 kVA	0

Where:

MD	is the rolling 12-month maximum half-hourly demand at an exit point (expressed in kVA);
DF	is the discount factor, which is set at 50%
$E_{Off\ Peak}$	is the total off peak energy for the billing period (expressed in kWh); and
E_{Total}	is the total energy (both on and off peak) for the billing period (expressed in kWh).

Notes:

1. This discount does not apply to the demand-length portion of the charge.

3.4 Reference Tariff 6 (RT6)

3.4.1 Tariff Calculation

RT6 consists of:

(a) a fixed metered demand charge (detailed in Table 4) which is payable each day based on the rolling 12-month maximum half-hourly demand at an exit point (expressed in kVA) multiplied by (1-Discount);

(b) a variable metered demand charge (detailed in Table 4) calculated by multiplying the demand price (in excess of lower threshold) by the rolling 12-month maximum half-hourly demand at an exit point (expressed in kVA) minus the lower threshold with the result multiplied by (1-Discount);

(c) if the metered demand is equal to or greater than 1,000 kVA a variable demand length charge calculated by multiplying the demand length price (detailed in Table 6) by the electrical distance to the zone substation by the rolling 12-month maximum half-hourly demand (expressed in kVA) minus 1,000 kVA (Note: a different rate applies after 10 km); and

(d) a fixed metering charge per revenue meter (detailed in Table 8) which is payable each day

Notes:

1. This tariff is similar to Reference Tariff 5 - (RT5) in section 3.3 but for customers connected at low voltage. The higher tariff rates reflect the additional cost of using the low voltage network.
2. The on and off peak periods for this tariff are defined in the following table (all times are Western Standard Time (WST)):

Monday – Friday (includes public holidays)			Saturday - Sunday
Off-peak	**On-Peak**	**Off-Peak**	**Off-Peak**
12:00am – 8:00am	8:00am – 10:00pm	10:00pm – 12:00am	All times

3.4.2 Discount Factor

Identical to RT5 detailed in section 3.3.2.

3.5 Reference Tariff 7 (RT7)

3.5.1 Tariff Calculation

RT7 consists of:

(a) If the contracted maximum demand (CMD) is less than 7,000 kVA:

i. a fixed demand charge for the first 1,000 kVA (detailed in Table 5) which is payable each day; plus

ii. a variable demand charge calculated by multiplying the applicable demand price (detailed in Table 5) by the CMD at an exit point (expressed in kVA) minus 1,000 kVA; plus

iii. a variable demand length charge calculated by multiplying the demand length price (detailed in Table 6) by the electrical distance to the zone substation by the CMD (expressed in kVA) minus 1,000 kVA (Note: a different rate applies after 10 km);

(b) If the CMD is equal to or greater than 7,000 kVA:

i. a variable demand charge calculated by multiplying the applicable demand price (detailed in Table 5) by the CMD at an exit point (expressed in kVA); plus

ii. a variable demand length charge calculated by multiplying the demand length price (detailed in Table 7) by the electrical distance to the zone substation by the CMD (expressed in kVA) (Note: a different rate applies after 10 km);

(c) a fixed metering charge per revenue meter (detailed in Table 8) which is payable each day;

(d) a fixed administration charge (detailed in Table 9) which is payable each day; and

(e) excess network usage charges (if applicable).

Notes:

1. For exit points located at the zone substation the fixed and demand charge specified in sections 3.5.1 (a)(i), (a)(ii) & (b)(i) is to be calculated using the transmission component only. In all other instances, the fixed and demand charge specified in sections 3.5.1 (a)(i), (a)(ii) & (b)(i) is to be calculated using the bundled charge.

3.5.2 Excess Network Usage Charges

An additional charge applies to this tariff where the peak half-hourly demand exceeds the nominated CMD during the billing period of the load.

The excess network usage charge (ENUC) is calculated by applying a factor to the excess usage as follows:

$$ENUC = ENUC_{Transmission} + ENUC_{Distribution}$$

Where

$ENUC_{Transmission}$ $= ENUM * (PD - CMD) * DC_{Transmission} / CMD$

$ENUC_{Distribution}$ $= ENUM * (PD - CMD) * (DC_{Distribution} + DLC) / CMD$

ENUM is the Excess network usage multiplier factor, which is set at 2

PD is the peak half-hourly demand during the billing period of the load (expressed in kVA)

CMD is the nominated CMD for the billing period of the load (expressed in kVA)

$DC_{Transmission}$ are the applicable transmission components of the fixed and variable demand charges for the billing period for the nominated CMD

$DC_{Distribution}$ are the applicable distribution components of the fixed and variable demand charges for the billing period for the nominated CMD

DLC are the applicable variable demand length charges for the billing period for the nominated CMD

Notes:

1. The ENUC does not include the metering or administration components of the tariff.

3.6 Reference Tariff 8 (RT8)

3.6.1 Tariff Calculation

RT8 consists of:

(a) If the contracted maximum demand (CMD) is less than 7,000 kVA:

i. a fixed demand charge for the first 1,000 kVA (detailed in Table 5) which is payable each day; plus

ii. a variable demand charge calculated by multiplying the applicable demand price (detailed in Table 5) by the CMD at an exit point (expressed in kVA) minus 1,000 kVA; plus

iii. a variable demand length charge calculated by multiplying the demand length price (detailed in Table 6) by the electrical distance to the zone substation by the CMD (expressed in kVA) minus 1,000 kVA (Note: a different rate applies after 10 km);

(b) If the CMD is equal to or greater than 7,000 kVA:

i. a variable demand charge calculated by multiplying the applicable demand price (detailed in Table 5) by the CMD at an exit point (expressed in kVA); plus

ii. a variable demand length charge calculated by multiplying the demand length price (detailed in Table 7) by the electrical distance to the zone substation by the CMD (expressed in kVA) (Note: a different rate applies after 10 km);

(c) a fixed low voltage charge (detailed in Table 10) which is payable each day;

(d) a variable low voltage charge calculated by multiplying the low voltage demand price (detailed in Table 10) by the CMD at an exit point (expressed in kVA);

(e) a fixed metering charge per revenue meter (detailed in Table 8) which is payable each day;

(f) a fixed administration charge (detailed in Table 9) which is payable each day; and

(g) excess network usage charges (if applicable).

Notes:

1. This tariff is identical to RT7 in section 3.5, with an additional low voltage charge to cover the use of transformers and LV circuits.

3.6.2 Excess Network Usage Charges

An additional charge applies to this tariff where the peak half-hourly demand exceeds the nominated CMD during the billing period of the load.

The excess network usage charge (ENUC) is calculated by applying a factor to the excess usage as follows:

$$ENUC = ENUC_{\text{Transmission}} + ENUC_{\text{Distribution}}$$

Where

$$ENUC_{\text{Transmission}} = ENUM * (PD – CMD) * DC_{\text{Transmission}} / CMD$$

$ENUC_{Distribution}$	$= ENUM * (PD – CMD) * (DC_{Distribution} + DLC + LVC) / CMD$
ENUM	is the Excess network usage multiplier factor, which is set at 2
PD	is the peak half-hourly demand during the billing period of the load (expressed in kVA)
CMD	is the nominated CMD for the billing period of the load (expressed in kVA)
$DC_{Transmission}$	are the applicable transmission components of the fixed and variable demand charges for the billing period for the nominated CMD
$DC_{Distribution}$	are the applicable distribution components of the fixed and variable demand charges for the billing period for the nominated CMD
DLC	are the applicable variable demand length charges for the billing period for the nominated CMD
LVC	are the applicable additional fixed and additional demand (low voltage) charges for the billing period for the nominated CMD

Notes:

1. The ENUC does not include the metering or administration components of the tariff.

3.7 Reference Tariff 9 (RT9)

RT9 consists of:

(a) a fixed use of system charge (detailed in Table 1) which is payable each day;

(b) a variable use of system charge calculated by multiplying the energy price (detailed in Table 1) by the estimated quantity of electricity consumed at an exit point (expressed in kWh and is based on the lamp wattage and illumination period); and

(c) a fixed asset charge based on the type of streetlight asset supplied (detailed in Table 2 – Current light types).

3.8 Reference Tariff 10 (RT10)

RT10 consists of:

(a) a fixed use of system charge (detailed in Table 1) which is payable each day; and

(b) a variable use of system charge calculated by multiplying the energy price (detailed in Table 1) by the estimated quantity of electricity consumed at an exit point (expressed in kWh and based on the nameplate rating of the connected equipment and the hours of operation).

3.9 Reference Tariff 11 (RT11)

3.9.1 Tariff Calculation

RT11 consists of:

(a) a variable connection charge calculated by multiplying the connection price (detailed in Table 11) by the loss-factor adjusted declared sent-out capacity (DSOC) at the entry point (expressed in kW);

(b) a variable control system service charge calculated by multiplying the control system service price (detailed in Table 15) by the nameplate output of the generator at the entry point (expressed in kW);

(c) a variable use of system charge calculated by multiplying the use of system price (based on the location of the electrically closest major generator and detailed in Table 13) by the loss-factor adjusted DSCO at the entry point (expressed in kW);

(d) If the DSOC is less than 7,000 kVA:

i. if the entry point is connected at 415 V or less and the DSOC is equal to or greater than 1,000 kVA a variable demand length charge calculated by multiplying the applicable demand length price (detailed in Table 6) by the electrical distance between the relevant HV network connection point and the electrically closest zone substation by the DSOC (expressed in kVA) minus 1,000 kVA (Note: a different rate applies after 10 km); or

ii. if the entry point is connected at greater than 415 V and the DSOC is equal to or greater than 1,000 kVA a variable demand length charge calculated by multiplying the applicable demand length price (detailed in Table 6) by the electrical distance between the entry point and the electrically closest zone substation by the DSOC (expressed in kVA) minus 1,000 kVA (Note: a different rate applies after 10 km);

(e) If the DSOC is equal to or greater than 7,000 kVA:

i. if the entry point is connected at 415 V or less a variable demand length charge calculated by multiplying the applicable demand length price (detailed in Table 7) by the electrical distance between the relevant HV network connection point and the electrically closest zone substation by the DSOC (expressed in kVA) (Note: a different rate applies after 10 km); or

ii. if the entry point is connected at greater than 415 V a variable demand length charge calculated by multiplying the applicable demand length price (detailed in Table 7) by the electrical distance between the entry point and the electrically closest zone substation by the DSOC (expressed in kVA) (Note: a different rate applies after 10 km);

(f) a fixed metering charge per revenue meter (detailed in Table 8) which is payable each day; and

(g) excess network usage charges (if applicable).

Notes:

1. The loss factor used to calculate the loss-factor adjusted DSOC is the relevant portion from the generator to the zone substation of the loss factor published by the IMO for that generator.

2. For this reference tariff a unity power factor is assumed when converting between kW and kVA.

3.9.2 Excess Network Usage Charges

An additional charge applies to this tariff where the peak half-hourly demand exceeds the nominated DSOC during the billing period except where Western Power deems the export of power in excess of DSOC was required for power system reliability and security purposes.

The excess network usage charge (ENUC) is calculated by applying a factor to the excess usage as follows:

$$ENUC = ENUC_{Transmission} + ENUC_{Distribution}$$

Where

$ENUC_{Transmission}$ = ENUM * (PD_{kW} – $DSOC_{kW}$) * TEPC / $DSOC_{kW}$

$ENUC_{Distribution}$ = ENUM * (PD_{kVA} – $DSOC_{kVA}$) * (DLC) / $DSOC_{kVA}$

ENUM is the Excess network usage multiplier factor, which is set at 2

PD is the peak half-hourly demand during the billing period (expressed in kVA and kW)

DSOC is the nominated DSOC for the billing period (expressed in kVA and kW)

TEPC is the sum of the variable connection charge, variable control system service charge and variable use of system charge for the billing period for the nominated DSOC

DLC is the applicable variable demand length charge for the billing period for the nominated DSOC

Notes:

1. The ENUC does not include the metering components of the tariff.

3.10 Reference Tariff 12 (RT12)

RT12 consists of:

(a) a fixed use of system charge (detailed in Table 1) which is payable each day;

(b) an on-peak use of system variable charge calculated by multiplying the on-peak energy price (detailed in Table 1) by the quantity of on-peak electricity transferred out of the network at the bi-directional point (expressed in kWh);

(c) a shoulder use of system variable charge calculated by multiplying the shoulder energy price (detailed in Table 1) by the quantity of shoulder electricity transferred out of the network at the bi-directional point (expressed in kWh);

(d) an off-peak use of system variable charge calculated by multiplying the off-peak energy price (detailed in Table 1) by the quantity of off-peak electricity transferred out of the network at the bi-directional point (expressed in kWh);

(e) a fixed metering charge per revenue meter (detailed in Table 1) which is payable each day;

(f) an on-peak variable metering charge calculated by multiplying the on-peak variable price (detailed in Table 1) by the quantity of on-peak electricity transferred out of the network at the bi-directional point (expressed in kWh);

(g) a shoulder variable metering charge calculated by multiplying the shoulder variable price (detailed in Table 1) by the quantity of shoulder electricity transferred out of the network at the bi-directional point (expressed in kWh); and

(h) an off-peak variable metering charge calculated by multiplying the off-peak variable price (detailed in Table 1) by the quantity of off-peak electricity transferred out of the network at the bi-directional point (expressed in kWh)

Notes:

1. For the avoidance of doubt, the RT12 tariff only applies to the quantity of energy that is transferred out of the network. Under the RT12 tariff, energy that is transferred into the network does not provide a credit to, or impose a charge on, the user or Western Power.

2. The on peak, shoulder and off peak periods for this tariff are defined in the following tables (all times are Western Standard Time (WST)):

Monday – Friday (excludes public holidays)				
Off-peak	**Shoulder**	**On-Peak**	**Shoulder**	**Off-Peak**
12:00am – 7:00am	7:00am - 2:00pm	2:00pm – 8:00pm	8:00pm - 10:00pm	10:00pm – 12:00am

Saturday - Sunday (includes public holidays)		
Off-peak	**Shoulder**	**Off-Peak**
12:00am – 7:00am	7:00am - 10:00pm	10:00pm – 12:00am

4 TRANSMISSION TARIFF APPLICATION GUIDE

4.1 Transmission Reference Tariff 1 (TRT1)

4.1.1 Tariff Calculation

TRT1 consists of:

(a) a User-specific charge that is to be an amount per day which reflects the costs to Western Power of providing the Connection Assets under an Access Contract, which may consist of capital and non-capital costs.

(b) a variable use of system charge calculated by multiplying the applicable use of system price (as detailed in Table 12 or where there is no applicable use of system price in Table 12 for the exit point, the price calculated by Western Power in accordance with Appendix A of the Price List Information) by the contracted maximum demand (CMD) at the exit point (expressed in kW);

(c) a variable common service charge calculated by multiplying the common service price (detailed in Table 14) by the CMD at the exit point (expressed in kW);

(d) a variable control system service charge calculated by multiplying the control system service price (detailed in Table 16) by the CMD at the exit point (expressed in kW);

(e) a fixed metering charge per revenue meter (detailed in Table 17) which is payable each day; and

(f) excess network usage charges (if applicable).

4.1.2 Excess Network Usage Charges

An additional charge applies to this tariff where the peak half-hourly demand exceeds the nominated CMD during the billing period of the load.

The excess network usage charge (ENUC) is calculated by applying a factor to the excess usage as follows:

$$ENUC = ENUM * (PD – CMD) * (UOS + CON + CS + CSS) / CMD$$

Where

ENUM	is the Excess network usage multiplier factor, which is set at 2
PD	is the peak half-hourly demand during the billing period of the load (expressed in kW)
CMD	is the nominated CMD for the billing period of the load (expressed in kW)
UOS	is the applicable variable use of system charge for the billing period for the nominated CMD
CON	is the applicable User-specific charge for the billing period
CS	is the applicable variable common service charge for the billing period for the nominated CMD
CSS	is the applicable variable control system service charge for the billing period for the nominated CMD

Notes:

1. The ENUC does not include the metering components of the tariff.

4.2 Transmission Reference Tariff 2 (TRT2)

4.2.1 Tariff Calculation

TRT2 consists of:

(a) a User-specific charge that is to be an amount per day which reflects the costs to Western Power of providing the Connection Assets under an Access Contract, which may consist of capital and non-capital costs.

(b) a variable use of system charge calculated by multiplying the applicable use of system price (detailed in Table 13 or where there is no applicable use of system price in Table 13 for the entry point, the price calculated by Western Power in accordance with Appendix A of the Price List Information) by the declared sent-out capacity (DSOC) at the entry point (expressed in kW);

(c) a variable control system service charge calculated by multiplying the control system service price (detailed in Table 15) by the nameplate output of the generator at the entry point (expressed in kW);

(d) a fixed metering charge per revenue meter (detailed in Table 17) which is payable each day; and

(e) excess network usage charges (if applicable).

4.2.2 Excess Network Usage Charges

An additional charge applies to this tariff where the peak half-hourly demand exceeds the nominated DSOC during the billing period except where Western Power deems the export of power in excess of DSOC was required for power system reliability and security purposes.

The excess network usage charge (ENUC) is calculated by applying a factor to the excess usage as follows:

ENUC = ENUM * (PD – DSOC) * (UOS + CON + CSS) / DSOC

Where

ENUM	is the Excess network usage multiplier factor, which is set at 2
PD	is the peak half-hourly demand during the billing period (expressed in kW)
DSOC	is the nominated DSOC for the billing period (expressed in kW)
UOS	is the applicable variable use of system charge for the billing period for the nominated DSOC
CON	is the applicable User-specific charge for the billing period
CSS	is the applicable variable control system service charge for the billing period

Notes:

1. The ENUC does not include the metering components of the tariff.

5 PRICE TABLES[1]

The tables in the following sections must be used in conjunction with the details in the sections above.

Table 5, Table 12 and Table 13 include a Transmission Node Identity (TNI) to uniquely identify zone substations. The TNIs meet the standard defined by the AEMO for WA[2].

All prices quoted in this Price List are **GST exclusive**.

5.1 Prices for energy-based tariffs on the distribution network

5.1.1 Use of system and metering prices

The prices in the following tables are applicable for reference tariffs: **RT1, RT2, RT3, RT4, RT9, RT10 and RT12.**

Table 1

	Fixed Price	Energy Rates			
	c/day	c/kWh	On Peak c/kWh	Off Peak c/kWh	Shoulder c/kWh
Reference tariff 1 - RT1					
Transmission Use of System	0.000	2.022			
Distribution Use of System	41.318	5.470			
Bundled Use of System Charges	41.318	7.492			
Metering Charges	5.244	1.172			
Reference tariff 2 - RT2					
Transmission Use of System	0.000	2.427			
Distribution Use of System	41.318	7.709			
Bundled Use of System Charges	41.318	10.136			
Metering Charges	5.244	1.172			
Reference tariff 3 - RT3					
Transmission Use of System	0.000	-	3.768	0.791	
Distribution Use of System	41.318	-	8.752	2.029	
Bundled Use of System Charges	41.318	-	12.520	2.821	
Metering Charges	5.244	-	1.505	1.505	
Reference tariff 4 - RT4					
Transmission Use of System	0.000	-	3.098	0.747	
Distribution Use of System	51.773	-	7.986	1.826	
Bundled Use of System Charges	51.773	-	11.084	2.573	
Metering Charges	10.499	-	0.255	0.255	
Reference tariff 9 – RT9					
Transmission Use of System	0.000	1.584			
Distribution Use of System	4.237	4.230			
Bundled Use of System Charges	4.237	5.814			

[1] Note: these tables have been slightly re-designed for 2012/13 to show relevant metering charges also.

[2] Australian Energy Market Operator, 9 January 2009, Operating Procedure – NEM Transmission Node Identities (TNI), p. 5

Reference tariff 10 – RT10					
Transmission Use of System	0.000	1.010			
Distribution Use of System	24.876	5.030			
Bundled Use of System Charges	24.876	6.040			
Reference tariff 12 – RT12					
Transmission Use of System	0.000		4.474	0.791	2.022
Distribution Use of System	41.318		12.132	2.029	5.470
Bundled Use of System Charges	41.318		16.606	2.820	7.492
Metering Charges	5.244		1.505	1.505	1.505

5.1.2 Streetlight asset prices

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

Table 2 – Current light types

Light Specification	Daily Charge c/day
42W CFL SE	27.487
42W CFL BH	29.212
42W CFL KN	32.920
50W MV	17.092
70W MH	48.048
70W HPS	23.631
80W MV	23.006
125W MV	28.603
150W MH	55.512
150W HPS	31.086
250W MH	55.512
250W HPS	31.086
250W MV	37.312
400W MV	39.175

5.2 Prices for demand-based tariffs on the distribution network (RT5 to RT8 and RT11[3])

5.2.1 Demand charges

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

Table 3

	Transmission		Distribution		Bundled Tariff	
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**	**Fixed c/day**	**Demand (in excess of lower threshold) c/kVA/day**
0 to 300	0.000	25.913	89.338	39.299	89.338	65.212
300 to 1000	7,773.900	19.183	11,879.038	29.541	19,652.938	48.724
1000 to 1500	21,202.000	10.959	32,557.738	12.359	53,759.738	23.318

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

Table 4

	Transmission		Distribution		Bundled Tariff	
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**	**Fixed c/day**	**Demand (in excess of lower threshold) c/kVA/day**
0 to 300	0.000	25.913	684.972	44.664	684.972	70.577
300 to 1000	7,773.900	19.183	14,084.172	34.906	21,858.072	54.089
1000 to 1500	21,202.000	10.959	38,518.372	17.133	59,720.372	28.092

[3] Note that some components of RT11 are in section 5.3

The prices in the following table are applicable for reference tariffs: **RT7 and RT8**.

Table 5

Zone Substation	TNI	Pricing Zone	Transmission			Distribution			Bundled		
			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)	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)	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)
Cook Street	WCKT	CBD	17,747.720	18.383	18.293	24,418.904	8.353	10.648	42,166.624	26.737	28.941
Forrest Avenue	WFRT	CBD	17,747.720	18.383	18.293	24,418.904	8.353	10.648	42,166.624	26.737	28.941
Hay Street	WHAY	CBD	17,747.720	18.383	18.293	24,418.904	8.353	10.648	42,166.624	26.737	28.941
Milligan Street	WMIL	CBD	17,747.720	18.383	18.293	24,418.904	8.353	10.648	42,166.624	26.737	28.941
Wellington Street	WWNT	CBD	17,747.720	18.383	18.293	24,418.904	8.353	10.648	42,166.624	26.737	28.941
Black Flag	WBKF	Goldfields Mining	17,747.720	35.229	32.731	24,418.904	4.222	7.108	42,166.624	39.451	39.839
Boulder	WBLD	Goldfields Mining	17,747.720	33.686	31.409	24,418.904	4.222	7.108	42,166.624	37.908	38.516
Bounty	WBNY	Goldfields Mining	17,747.720	65.559	58.729	24,418.904	4.222	7.108	42,166.624	69.782	65.837
West Kalgoorlie	WWKT	Goldfields Mining	17,747.720	30.343	28.544	24,418.904	4.222	7.108	42,166.624	34.566	35.652
Albany	WALB	Mixed	17,747.720	32.154	30.096	24,418.904	9.316	11.474	42,166.624	41.470	41.569
Boddington	WBOD	Mixed	17,747.720	16.679	16.832	24,418.904	9.316	11.474	42,166.624	25.996	28.306
Bunbury Harbour	WBUH	Mixed	17,747.720	16.709	16.857	24,418.904	9.316	11.474	42,166.624	26.025	28.331
Busselton	WBSN	Mixed	17,747.720	28.242	26.743	24,418.904	9.316	11.474	42,166.624	37.558	38.216
Byford	WBYF	Mixed	17,747.720	17.468	17.508	24,418.904	9.316	11.474	42,166.624	26.784	28.981
Capel	WCAP	Mixed	17,747.720	23.686	22.838	24,418.904	9.316	11.474	42,166.624	33.002	34.311
Chapman	WCPN	Mixed	17,747.720	34.626	32.215	24,418.904	9.316	11.474	42,166.624	43.942	43.688
Darlington	WDTN	Mixed	17,747.720	18.840	18.684	24,418.904	9.316	11.474	42,166.624	28.156	30.157
Durlacher Street	WDUR	Mixed	17,747.720	29.560	27.873	24,418.904	9.316	11.474	42,166.624	38.876	39.346
Eneabba	WENB	Mixed	17,747.720	28.379	26.860	24,418.904	9.316	11.474	42,166.624	37.695	38.334
Geraldton	WGTN	Mixed	17,747.720	29.560	27.873	24,418.904	9.316	11.474	42,166.624	38.876	39.346
Marriott Road	WMRR	Mixed	17,747.720	16.741	16.885	24,418.904	9.316	11.474	42,166.624	26.057	28.359
Muchea	WMUC	Mixed	17,747.720	19.465	19.220	24,418.904	9.316	11.474	42,166.624	28.781	30.693
Northam	WNOR	Mixed	17,747.720	28.134	26.651	24,418.904	9.316	11.474	42,166.624	37.451	38.124
Picton	WPIC	Mixed	17,747.720	18.800	18.649	24,418.904	9.316	11.474	42,166.624	28.116	30.123
Rangeway	WRAN	Mixed	17,747.720	29.560	27.873	24,418.904	9.316	11.474	42,166.624	38.876	39.346
Sawyers Valley	WSVL	Mixed	17,747.720	28.751	27.179	24,418.904	9.316	11.474	42,166.624	38.067	38.652
Yanchep	WYCP	Mixed	17,747.720	18.610	18.487	24,418.904	9.316	11.474	42,166.624	27.926	29.961
Yilgarn	WYLN	Mixed	17,747.720	30.351	28.551	24,418.904	9.316	11.474	42,166.624	39.667	40.024
Baandee	WBDE	Rural	17,747.720	40.071	36.882	24,418.904	4.533	7.374	42,166.624	44.605	44.256
Beenup	WBNP	Rural	17,747.720	40.389	37.155	24,418.904	4.533	7.374	42,166.624	44.922	44.529
Bridgetown	WBTN	Rural	17,747.720	24.105	23.197	24,418.904	4.533	7.374	42,166.624	28.638	30.571
Carrabin	WCAR	Rural	17,747.720	46.012	41.975	24,418.904	4.533	7.374	42,166.624	50.546	49.349
Collie	WCOE	Rural	17,747.720	30.585	28.751	24,418.904	4.533	7.374	42,166.624	35.118	36.125
Coolup	WCLP	Rural	17,747.720	32.557	30.441	24,418.904	4.533	7.374	42,166.624	37.090	37.815
Cunderdin	WCUN	Rural	17,747.720	36.667	33.964	24,418.904	4.533	7.374	42,166.624	41.200	41.338
Katanning	WKAT	Rural	17,747.720	31.923	29.898	24,418.904	4.533	7.374	42,166.624	36.456	37.272
Kellerberrin	WKEL	Rural	17,747.720	38.948	35.919	24,418.904	4.533	7.374	42,166.624	43.481	43.293
Kojonup	WKOJ	Rural	17,747.720	20.399	20.021	24,418.904	4.533	7.374	42,166.624	24.933	27.395
Kondinin	WKDN	Rural	17,747.720	23.661	22.816	24,418.904	4.533	7.374	42,166.624	28.194	30.190

Zone Substation	TNI	Pricing Zone	Transmission			Distribution			Bundled		
			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)	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)	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)
Manjimup	WMJP	Rural	17,747.720	23.903	23.024	24,418.904	4.533	7.374	42,166.624	28.436	30.398
Margaret River	WMRV	Rural	17,747.720	38.374	35.427	24,418.904	4.533	7.374	42,166.624	42.907	42.801
Merredin	WMER	Rural	17,747.720	35.061	32.588	24,418.904	4.533	7.374	42,166.624	39.594	39.962
Moora	WMOR	Rural	17,747.720	12.863	13.561	24,418.904	4.533	7.374	42,166.624	17.396	20.935
Mount Barker	WMBR	Rural	17,747.720	26.311	25.088	24,418.904	4.533	7.374	42,166.624	30.844	32.462
Narrogin	WNGN	Rural	17,747.720	30.514	28.690	24,418.904	4.533	7.374	42,166.624	35.047	36.064
Pinjarra	WPNJ	Rural	17,747.720	39.793	36.644	24,418.904	4.533	7.374	42,166.624	44.327	44.018
Regans	WRGN	Rural	17,747.720	18.294	18.216	24,418.904	4.533	7.374	42,166.624	22.827	25.590
Three Springs	WTSG	Rural	17,747.720	26.226	25.015	24,418.904	4.533	7.374	42,166.624	30.759	32.389
Wagerup	WWGP	Rural	17,747.720	26.623	25.355	24,418.904	4.533	7.374	42,166.624	31.156	32.729
Wagin	WWAG	Rural	17,747.720	17.011	17.116	24,418.904	4.533	7.374	42,166.624	21.545	24.491
Wundowie	WWUN	Rural	17,747.720	29.092	27.471	24,418.904	4.533	7.374	42,166.624	33.625	34.845
Yerbillon	WYER	Rural	17,747.720	29.948	28.205	24,418.904	4.533	7.374	42,166.624	34.482	35.579
Amherst	WAMT	Urban	17,747.720	44.736	40.880	24,418.904	4.533	7.374	42,166.624	49.269	48.254
Arkana	WARK	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Australian Paper Mills	WAPM	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Beechboro	WBCH	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Belmont	WBEL	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Bentley	WBTY	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Bibra Lake	WBIB	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
British Petroleum	WBPM	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Canning Vale	WCVE	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Clarence Street	WCLN	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Clarkson	WCKN	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Cockburn Cement	WCCT	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Collier	WCOL	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Cottesloe	WCOT	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Edmund Street	WEDD	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Forrestfield	WFFD	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Gosnells	WGNL	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Hadfields	WHFS	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Hazelmere	WHZM	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Henley Brook	WHBK	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Herdsman Parade	WHEP	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Joel Terrace	WJTE	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Joondalup	WJDP	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Joondanna	WJDA	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Kalamunda	WKDA	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Kambalda	WKBA	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Kewdale	WKDL	Urban	17,747.720	33.686	31.409	24,418.904	1.487	4.763	42,166.624	35.172	36.172
Landsdale	WLDE	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Malaga	WMLG	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686

Zone Substation	TNI	Pricing Zone	Transmission			Distribution			Bundled		
			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)	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)	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)
Mandurah	WMHA	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Manning Street	WMAG	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Mason Road	WMSR	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Meadow Springs	WMSS	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Medical Centre	WMCR	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Medina	WMED	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Midland Junction	WMJX	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Morley	WMOY	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Mullaloo	WMUL	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Mundaring Weir	WMWR	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Murdoch	WMUR	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Myaree	WMYR	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Nedlands	WNED	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
North Beach	WNBH	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
North Fremantle	WNFL	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
North Perth	WNPH	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
OConnor	WOCN	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Osborne Park	WOPK	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Padbury	WPBY	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Piccadilly	WPCY	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Riverton	WRTN	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Rivervale	WRVE	Urban	17,747.720	32.432	30.334	24,418.904	1.487	4.763	42,166.624	33.919	35.097
Rockingham	WROH	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Shenton Park	WSPA	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Sth Ftle Power Station	WSFT	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Southern River	WSNR	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Tate Street	WTTS	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
University	WUNI	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Victoria Park	WVPA	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Waikiki	WWAI	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Wanneroo	WWNO	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Welshpool	WWEL	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Wembley Downs	WWDN	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Willeton	WWLN	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686
Yokine	WYKE	Urban	17,747.720	19.119	18.923	24,418.904	1.487	4.763	42,166.624	20.605	23.686

5.2.2 Demand length charges

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

Table 6

	Demand-Length Charge	
Pricing Zone	**For kVA >1000 and first 10 km length (c/kVA.km/day)**	**For kVA >1000 and length in excess of 10 km (c/kVA.km/day)**
CBD	0.000	0.000
Urban	1.123	0.786
Mining	0.241	0.169
Mixed	0.528	0.369
Rural	0.367	0.256

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

Table 7

	Demand-Length Charge	
Pricing Zone	**For first 10 km length (c/kVA.km/day)**	**For length in excess of 10 km (c/kVA.km/day)**
CBD	0.000	0.000
Urban	0.963	0.674
Mining	0.207	0.145
Mixed	0.452	0.317
Rural	0.314	0.220

5.2.3 Metering prices

The prices in the following table are applicable for reference tariffs: **RT5, RT6, RT7, RT8 and RT11**.

Table 8

Metering Equipment Funding	Voltage	c/revenue meter/day
Western Power funded	High Voltage (6.6 kV or higher)	1591.215
	Low voltage (415 volts or less)	286.720
Customer funded	High Voltage (6.6 kV or higher)	510.493
	Low Voltage (415 volts or less)	91.987

5.2.4 Administration charges

The prices in the following table are applicable for reference tariffs: **RT7 and RT8**.

Table 9

CMD	Price (c/day)
>=7,000 kVA	5,672.600
<7,000 kVA	3,257.790

5.2.5 LV Prices

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

Table 10

Category	Price (c/day)
Fixed	595.631
Demand	4.755/kVA

5.2.6 Connection Price

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

Table 11

	Connection Price c/kW/day
Connection Price	6.783

5.3 Transmission prices

5.3.1 Use of system prices

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

Table 12

Substation	TNI	Use of System Price c/kW/day
Albany	WALB	18.212
Alcoa Pinjarra	WAPJ	8.162
Amherst	WAMT	4.689
Arkana	WARK	6.281
Australian Fused Materials	WAFM	3.398
Australian Paper Mills	WAPM	6.579
Baandee (WC)	WBDE	24.761
Beckenham	WBEC	17.124
Beechboro	WBCH	5.564
Beenup	WBNP	25.050
Belmont	WBEL	4.818

Substation	TNI	Use of System Price c/kW/day
Bentley	WBTY	8.866
Bibra Lake	WBIB	6.302
Binningup Desalination Plant	WBDP	3.898
Black Flag	WBKF	21.051
Boddington Gold	WBOD	3.841
Boddington (Local)	WABD	3.841
Boddington Reynolds	WRBD	3.732
Boulder	WBLD	19.618
Bounty	WBNY	49.206
Bridgetown	WBTN	10.231
British Petroleum	WBPM	7.091
Broken Hill Kwinana	WBHK	6.250
Bunbury Harbour	WBUH	3.868
Busselton	WBSN	14.579
Byford	WBYF	4.573
Canning Vale	WCVE	4.271
Capel	WCAP	10.348
Carrabin	WCAR	30.167
Cataby Kerr McGee	WKMC	12.161
Chapman	WCPN	20.509
Clarence Street	WCLN	9.044
Clarkson	WCKN	6.770
Cockburn Cement	WCCT	3.334
Cockburn Cement Ltd	WCCL	3.615
Collie	WCOE	16.127
Collier	WCOL	9.254
Cook Street	WCKT	6.805
Coolup	WCLP	17.922
Cottesloe	WCTE	8.231
Cunderdin	WCUN	21.662
Darlington	WDTN	5.847
Edgewater	WEDG	6.309
Edmund Street	WEDD	6.935
Eneabba	WENB	14.707
Forrest Ave	WFRT	9.321
Forrestfield	WFFD	5.606
Geraldton	WGTN	15.803
Glen Iris	WGNI	3.986
Golden Grove	WGGV	42.046
Gosnells	WGNL	4.618
Hadfields	WHFS	5.772
Hay Street	WHAY	7.842
Hazelmere	WHZM	5.329
Henley Brook	WHBK	5.329
Herdsman Parade	WHEP	11.082
Joel Terrace	WJTE	8.980
Joondalup	WJDP	6.677
Kalamunda	WKDA	5.530
Katanning	WKAT	17.345

Substation	TNI	Use of System Price c/kW/day
Kellerberrin	WKEL	23.738
Kojonup	WKOJ	6.859
Kondinin	WKDN	9.827
Kwinana Alcoa	WAKW	1.343
Kwinana Desalination Plant	WKDP	3.492
Landsdale	WLDE	5.761
Malaga	WMLG	4.988
Mandurah	WMHA	5.534
Manjimup	WMJP	10.047
Manning Street	WMAG	7.183
Margaret River	WMRV	23.216
Marriott Road Barrack Silicon Smelter	WBSI	4.452
Marriott Road (Local)	WLMR	3.898
Mason Road	WMSR	2.138
Mason Road CSBP	WCBP	3.816
Mason Road Hismelt	WHIS	8.354
Mason Road Kerr McGee	WKMK	2.138
Meadow Springs	WMSS	5.144
Medical Centre	WMCR	9.378
Medina	WMED	3.067
Merredin 66kV	WMER	20.201
Midland Junction	WMJX	6.797
Milligan Street	WMIL	8.883
Moora	WMOR	12.238
Morley	WMOY	7.197
Mt Barker	WMBR	16.063
Muchea Kerr McGee	WKMM	9.708
Muchea (Local)	WLMC	6.428
Mullaloo	WMUL	6.677
Murdoch	WMUR	4.160
Mundaring Weir	WMWR	10.886
Myaree	WMYR	8.405
Narrogin	WNGN	24.508
Nedlands	WNED	8.205
North Beach	WNBH	7.095
North Fremantle	WNFL	8.030
North Perth	WNPH	5.275
Northam	WNOR	14.479
O'Connor	WOCN	7.436
Osborne Park	WOPK	7.042
Padbury	WPBY	6.677
Parkeston	WPRK	19.618
Parklands	WPLD	5.370
Piccadilly	WPCY	18.812
Picton 66kv	WPIC	5.810
Pinjarra	WPNJ	4.942
Rangeway	WRAN	15.803
Regans	WRGN	12.161
Riverton	WRTN	4.160

Substation	TNI	Use of System Price c/kW/day
Rivervale	WRVE	9.643
Rockingham	WROH	4.131
Sawyers Valley	WSVL	15.052
Shenton Park	WSPA	8.252
Southern River	WSNR	4.518
South Fremantle 22kV	WSFT	4.900
Summer St	WSUM	12.141
Tate Street	WTTS	7.826
Three Springs	WTSG	12.522
Tomlinson Street	WTLN	9.444
University	WUNI	9.724
Victoria Park	WVPA	7.596
Wagerup	WWGP	3.775
Wagin	WWAG	14.769
Waikiki	WWAI	4.567
Wangara	WWGA	6.677
Wanneroo	WWNO	6.222
WEB Grating	WWEB	45.114
Wellington Street	WWNT	9.321
Welshpool	WWEL	4.874
Wembley Downs	WWDN	8.503
West Kalgoorlie	WWKT	16.516
Western Collieries	WWCL	2.276
Western Mining	WWMG	2.675
Westralian Sands	WWSD	9.037
Willeton	WWLN	4.271
Worsley	WWOR	2.940
Wundowie	WWUN	15.548
Yanchep	WYCP	5.634
Yerbillon	WYER	29.005
Yilgarn	WYLN	16.538
Yokine	WYKE	6.863

The prices in the following table are applicable for reference tariffs: **RT11 and TRT2**.

Table 13

Substation	TNI	Use of System c/kW/day
Albany Windfarm	WALB	3.242
Boulder	WBLD	2.887
Bluewaters	WBWP	4.011
Cockburn PWS	WCKB	2.017
Collgar	WCGW	3.036
Collie PWS	WCPS	3.382
Emu Downs	WEMD	3.195
Geraldton GT	WGTN	0.683
Kemerton PWS	WKEM	3.242
Kwinana Alcoa	WAKW	2.017
Kwinana Donaldson Road (Western Energy)	WKND	1.904
Kwinana PWS	WKPS	2.017
Landweir (Alinta)	WLWT	2.989
Mason Road	WMSR	1.904
Mason Road Hismelt	WHIS	1.653
Muja PWS	WMPS	3.242
Mungarra GTs	WMGA	3.527
Newgen Kwinana	WNGK	2.331
Newgen Neerabup	WGNN	1.760
Oakley (Alinta)	WOLY	3.375
Parkeston	WPKS	3.480
Pinjar GTs	WPJR	1.760
Alcoa Pinjarra	WAPJ	3.544
Tiwest GT	WKMK	1.967
Wagerup Alcoa	WAWG	2.306
Walkaway Windfarm	WWWF	3.884
West Kalgoorlie GTs	WWKT	2.830
Worsley	WWOR	3.029

5.3.2 Common Service Prices

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

Table 14

	Common Service Price c/kW/day
Common Service Price	6.179

5.3.3 Control System Service Prices

The prices in the following table are applicable for reference tariffs: **RT11 and TRT2**.

Table 15

	Price (c/kW/day)
Control System Service Price (Generators)	0.204

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

Table 16

	Price (c/kW/day)
Control System Service Price (Loads)	1.436

5.3.4 Metering prices

The prices in the following table are applicable for reference tariffs: **TRT1 and TRT2**.

Table 17

	c/metering unit/day
Transmission Metering	4,601.41

6 NON REFERENCE SERVICE TARIFFS

The fees listed below are referred to in the Applications and Queuing Policy and the Standard Access Contract. Western Power treats these as non-reference services and notes that the list of tariffs included in this section does not include tariffs for all non-reference services provided by Western Power.

All prices quoted in this Price List are **GST exclusive**.

6.1 Lodgement Fees under the Application and Queuing Policy

Table 18

Lodgement Fee	Price
New Standard Access Contract Fee	$1,150.00
Access Contract Modification Fee	$140.00 per modification
Transmission Enquiry Application Fee	$3,500.00
Transmission Connection Application Fee	$5,000.00
Distribution Connection Application Fee	$2,500.00

Table 19

Application for Reference Service	New Connection Point Fee
A1 – Anytime Energy (Residential) Exit Service	$0.00 per connection point
A2 – Anytime Energy (Business) Exit Service	$0.00 per connection point
A3 – Time of Use Energy (Residential) Exit Service	$0.00 per connection point
A4 – Time of Use Energy (Business) Exit Service	$0.00 per connection point
A5 – High Voltage Metered Demand Exit Service	$44.00 per connection point
A6 – Low Voltage Metered Demand Exit Service	$44.00 per connection point
A7 – High Voltage Contract Maximum Demand Exit Service	$88.00 per connection point
A8 – Low Voltage Contract Maximum Demand Exit Service	$88.00 per connection point
A9 – Streetlighting Exit Service	$0.00 per connection point
A10 – Un-Metered Supplies Exit Service	$0.00 per connection point
A11 – Transmission Exit Service	$175.00 per connection point
B1 – Distribution Entry Service	$175.00 per connection point
B2 – Transmission Entry Service	$175.00 per connection point
C1 – Anytime Energy (Residential) Bi-directional Service	$0.00 per connection point
C2 – Anytime Energy (Business) Bi-directional Service	$0.00 per connection point
C3 – Time of Use (Residential) Bi-directional Service	$0.00 per connection point
C4 – Time of Use (Business) Bi-directional Service	$0.00 per connection point

Appendix 3 Western Power’s Proposed Price List Information

2012/13 Price List Information

ELECTRICITY NETWORKS CORPORATION
("WESTERN POWER")

ABN 18 540 492 861

DM#9145331

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 Price List's compliance with the Access Arrangement;
- 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 Economic Regulation Authority (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 2012/13 Foreword

This document is the Price List Information for the 2012/13 Price List that will apply from 1 July 2012 until the earlier of 30 June 2013 or the commencement of the third access arrangement period (AA3).

The second access arrangement period(AA2) was due to end on 30 June 2012 with AA3 commencing 1 July 2012. However, delays with the Access Arrangement approval process have meant that from 1 July 2012 Western Power will still be operating under AA2. There is no defined revenue cap for 2012/13 under AA2, therefore the revenue cap for 2012/13 in the Authority's draft decision on AA3[1] has been used for the purpose of setting 2012/13 prices. Consistent with previous years of AA2, all prices have been scaled to achieve the revenue cap.

Transmission – all prices are unchanged from 2011/12.

Distribution – all prices are increased by 13% relative to 2011/12 prices.

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1 http://www.erawa.com.au/cproot/10284/2/20120329%20Draft%20Decision%20on%20Proposed%20Revisions%20to%20the%20AA%20for%20the%20WPN%20-%20Submitted%20by%20WP.pdf

[Note that this increase is sometimes inflated to 13.3% due to the effects of the leap year in 11/12 on annual fixed prices being converted to a daily charge. The opposite situation occurred last year.]

1.2.1 New transmission connections

Sections 4.1.1(b) and 4.2.1(b) of the Price List for 2012/13 have been amended to clarify the link between Appendix A of this document and the relevant prices for reference tariffs TRT1 and TRT2,

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.

With the exception of the introduction of the RT12 bi-directional tariff in AA2, Western Power has maintained the remaining network tariff structure for the reference services offered under the Access Arrangement since its commencement on 1 July 2006.

1.4 Revenue requirement for 2012/13

1.4.1 Maximum Transmission Regulated Revenue

The following table demonstrates the derivation of the maximum transmission regulated revenue in accordance with:

- the derivation of the k-factor for this pricing year in accordance with section 5.36 of the Access Arrangement; and
- section 5.35 of the Access Arrangement.

Table 1 – Maximum Transmission Regulated Revenue and Transmission K-Factor for 2012/13 ($M real as at 30 June 2009)

	2012/13
TR_t	352.0
plus $AA1_t$[2]	0.0
plus TK_t	24.4
MTR_t	**376.4**

The derivation of the transmission system cost of supply cost pools and tariffs require the reference service revenue as an input in nominal terms. The following table details the transmission reference service revenue in nominal terms (please see section 1.4.3 for details of the inflation factor used).

Table 2 - Transmission Reference Service Revenue for 2012/13 ($M)

	Revenue (Real)	**Revenue (Nominal)**
Reference Service Revenue ($MTR_{2012/13}$)	376.4	422.5

1.4.2 Maximum Distribution Regulated Revenue

The following table demonstrates the derivation of the maximum distribution regulated revenue in accordance with:

- the derivation of the k-factor for this pricing year in accordance with section 5.47 of the Access Arrangement; and
- section 5.46 of the Access Arrangement.

Table 3 – Maximum Distribution Regulated Revenue and Distribution K-Factor for 2012/13 ($M real as at 30 June 2009)

	2012/13
DR_t	698.1
plus TEC_t	166.2
plus $AA1_t$[3]	0.0
plus DK_t	17.3
MDR_t	**881.7**

The derivation of the distribution system cost of supply cost pools and tariffs require the reference service revenue as an input in nominal terms. The following table details the distribution reference service revenue in nominal terms (please see section 1.4.3 for details of the inflation factor used).

Table 4 - Distribution Reference Service Revenue for 2012/13 ($M)

	Revenue (Real)	**Revenue (Nominal)**
Reference Service Revenue ($MDR_{2012/13}$)	881.7	989.7

[2] It is assumed that this term is zero.
[3] It is assumed that this term is zero.

1.4.3 Derivation of Inflation Factor

In sections 1.4.1 and 1.4.2 Western Power has inflated the reference service revenue from real terms to nominal terms by using the relevant published March quarter CPI data (per sections 5.35 and 5.46 of the Access Arrangement), where available, and using forecast inflation based on the Reserve Bank's inflation forecasts.

Table 5 - Derivation of 2012/13 Inflation Factor

March 2009 – March 2010 – Actual	2.89%
March 2010 – March 2011 – Actual	3.33%
March 2011 – March 2012 – Forecast	2.5%
March 2012 – March 2013 – Forecast	3%
Derived Inflation Factor	1.122

1.5 Forecast revenue recovery

The following table sets out the reference service revenue, by tariff, which is forecast to be collected when applying the 2012/13 Price List.

Table 6 – Reference Service Revenue Forecast 2012/13 ($M Nominal)

	kWh	Customer Numbers	Forecast Transmission Revenue Recovered	Forecast Distribution Revenue Recovered
TRT1 – Transmission Exit	N/A	26	33.6	0.0
TRT2 – Transmission Entry (includes LV Gens etc.)	N/A	29	77.2	0.0
RT1 - Anytime Energy (Residential)	5,319,275,949	928,361	107.5	511.1
RT2 - Anytime Energy (Business)	1,626,702,520	90,014	39.5	159.8
RT3 - Time of Use Energy (Residential)	213,268,785	24,799	4.6	18.4
RT4 - Time of Use Energy (Business)	2,009,149,700	12,687	45.4	124.2
RT5 - High Voltage Metered Demand	405,345,690	184	10.2	16.4
RT6 - Low Voltage Metered Demand	1,343,018,790	2,130	34.2	66.9
RT7 - High Voltage Contract Maximum Demand	3,089,046,010	335	63.0	47.2
RT8 - Low Voltage Contract Maximum Demand	239,760,628	64	5.5	8.6
RT9 – Streetlighting	121,595,204	240,095	1.9	32.6
RT10 - Unmetered Supplies	34,479,656	15,801	0.3	3.2
RT11 - Distribution Entry	N/A	21	0	0.7
RT12 – Time of Use Energy (Bidirectional Residential)	0	0	0	0
TOTAL	**14,401,642,932**	**1,314,491**	**423.0**	**989.1**
Over/(Under) recovery compared to maximum transmission/distribution regulated revenue			**0.5**	**(0.6)**

Note: The standby cost pool and associated revenue has been removed from reference services due to the standby service being provided as a non-reference service.

2 Pricing Principles Overview

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 where possible. 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. 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 (or no metering at all) 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 3 and 4.

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.

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 >1 MVA maximum demand
- High Voltage <1 MVA maximum demand
- Low Voltage >1 MVA 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 6 and 7.

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 Transmission System Cost of Supply

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

3.1 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.

3.1.1 Connection Services for Exit Points Cost Pool

The Connection Services for Exit Points Cost Pool includes the Gross Optimised Deprival Value (GODV) 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).

3.1.2 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).

3.1.3 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.

3.1.4 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.

3.1.5 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); and
- Adjustments for under or over recovery of revenue expected for any reason in any other tariff component.

3.1.6 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.

3.1.7 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.

3.2 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 of all relevant assets.

3.2.1 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

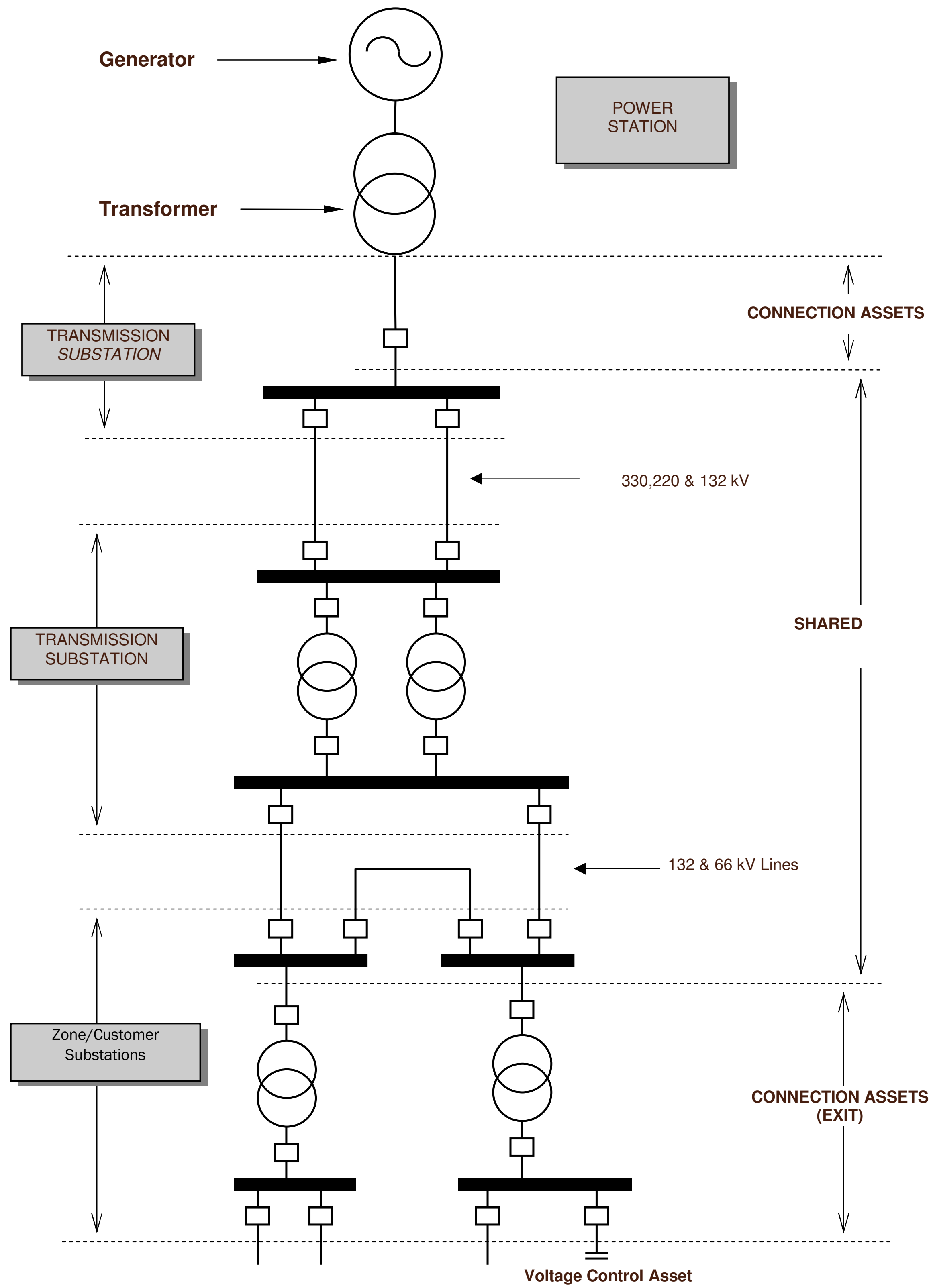

Figure 1 - Transmission Network Assets

3.2.2 Asset Valuation

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

3.2.3 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.

3.3 Methodology of Allocating to Cost Pools

3.3.1 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.

3.4 Cost Pool Allocations

Applying the above methodology, the following cost pool revenues were derived (before applying pricing side constraints) for 2012/13:

Table 7 - Transmission Pricing Cost Pools for 2012/13 ($M Nominal)

Cost Pool	Allocated Revenue
Entry Connection	8.5
Exit Connection HV	0.7
Exit Connection LV	96.1
Control System Services for Generators	4.6
Control System Services for Loads	23.3
Use Of System for Generators	62.4
Use Of System for Loads	126.4
Common Service for Loads (including Voltage Control)	99.9
Metering CT/VT	0.5
Total Reference Service Revenue	**422.5**

Note: The standby cost pool and associated revenue has been removed from reference services due to the standby service being provided as a non-reference service.

4 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.

4.1 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

4.2 Customer Groups

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

- High Voltage >1 MVA maximum demand
- High Voltage <1 MVA maximum demand
- Low Voltage >1 MVA 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

4.3 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.

4.3.1 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.

4.3.2 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.

4.3.3 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, for example Merredin.

4.3.4 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, for example Yanchep.

4.3.5 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 (Urban zone).

4.4 Methodology of Deriving the Cost of Supply

4.4.1 Flowchart

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

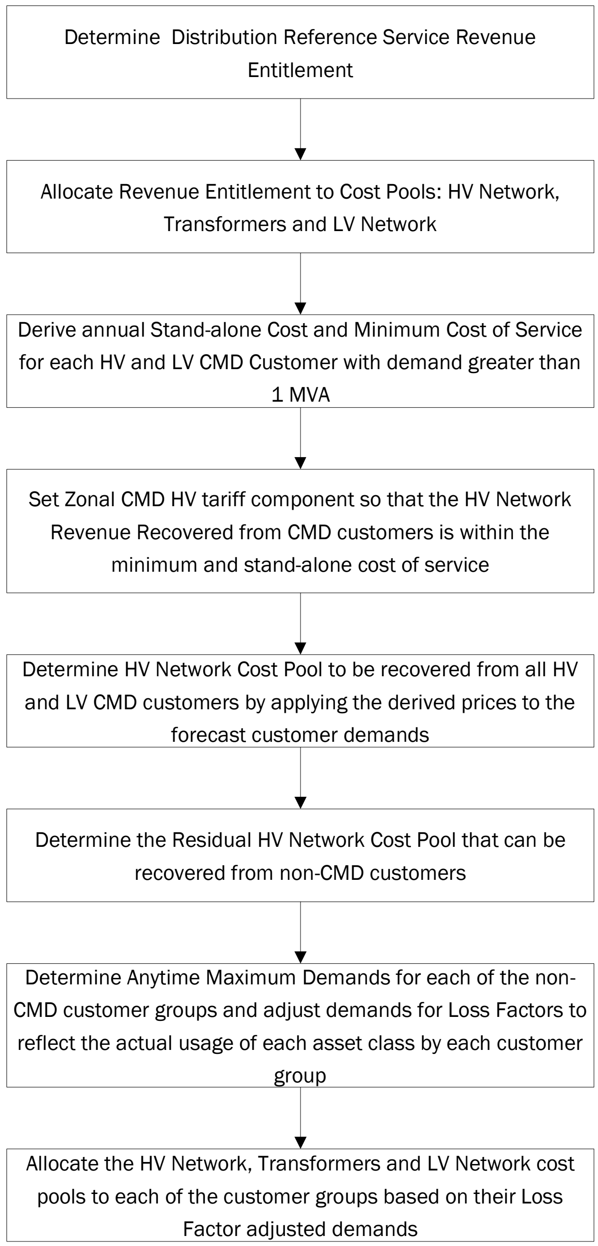

Figure 2 - Distribution Cost of Supply Flow Chart

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

4.4.2 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 Authority in the Access Arrangement.

The forecast distribution network revenue entitlement includes an amount for the 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.

4.4.3 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 GODV of each asset category as a proportion of the total GODV.

4.4.4 Derive HV annual stand-alone cost and incremental cost of supply for all 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 location on the network and 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 and stand-alone cost of supply. This approach is consistent with the requirements of section 7.3 of the Code.

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 7.

4.4.5 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.

4.4.6 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 (%)
Unmetered	8
Streetlights	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

4.4.7 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.

4.4.7.1. 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 should be allocated on demand.

4.4.7.2. 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.

4.4.7.3. 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.

4.4.8 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.

4.4.9 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

4.4.10 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

4.4.11 Streetlighting Costs

Allocation of network costs to streetlighting is in two components - the use of network costs and the costs associated with the streetlight asset itself.

4.4.11.1. Use of Network Costs

Streetlighting 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, streetlighting effectively does not contribute to network costs but simply assists in improving the load factor.

On this basis HV, LV and transformer costs are allocated on a fixed and variable basis as for other customer groups, but with customer numbers reduced by a factor of 10.

4.4.11.2. Streetlight Asset Costs

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

4.4.12 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.

4.4.13 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.

4.5 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 2012/13 ($M Nominal)

	Locational Zone					
Cost Pool	**CBD**	**Urban**	**Goldfields Mining**	**Mixed**	**Rural**	**Total**
High Voltage Network	4.7	149.8	4.3	102.1	106.7	367.5
High Voltage Network > 1,000 kVA	12.8	36.3	3.6	10.0	4.0	66.7
High Voltage Network Total	**17.4**	**186.1**	**8.0**	**112.1**	**110.7**	**434.2**
Low Voltage Network	10.4	164.6	1.6	45.0	18.4	239.9
Transformers	6.1	61.1	1.6	28.7	19.2	116.8
Streetlight Assets						26.5
Metering						58.0
Administration						114.2
TOTAL Reference Service Revenue						**989.7**

Table 9 - Distribution Customer Groups for 2012/13 ($M Nominal)

								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	15,801	15,801	1.4	0.2	1.1	0.2	0.1	0.0	0.0	0.5
Streetlights	30	122	33	33	3	240,095	24,010	2.6	1.4	1.5	0.1	0.6	26.5	0.0	1.1
Residential	2,494	5,533	2,702	2,702	2,702	953,160	953,160	95.5	114.4	60.6	105.6	53.6	0.0	42.1	66.4
Small Business	519	1,400	543	543	543	88,435	88,435	14.7	27.6	5.6	21.5	11.6	0.0	9.2	11.3
General Business - Small	502	1,136	525	525	525	12,645	12,645	1.7	25.3	0.9	20.7	11.0	0.0	2.7	9.3
General Business - Medium	429	962	448	448	404	2,537	2,284	0.3	18.8	0.2	15.8	8.8	0.0	1.3	7.7
General Business - Large	513	1,187	530	530	53	1,010	101	0.1	21.4	0.0	2.0	10.1	0.0	0.9	9.2
LV greater than 1000kVA	1,024	533	1,058	1,058	106	268	27	4.0	51.7	0.0	4.1	20.9	0.0	0.3	3.2
HV less than 1000kVA	49	166	50	0	0	107	0	0.0	1.7	0.0	0.0	0.0	0.0	0.3	0.9
HV>1000	818	2,933	835	0	0	392	0	16.2	35.4	0.0	0.0	0.0	0.0	1.1	4.7
TOTAL	**6,383**	**14,006**	**6,731**	**5,845**	**4,342**	**1,314,450**	**1,096,461**	**136.4**	**297.9**	**69.9**	**170.1**	**116.8**	**26.5**	**58.0**	**114.2**

5 Reference Tariff Structure

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

5.1 Reference Services and 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 – Unmetered Supplies Exit Service	RT10
A11 – Transmission Exit Service	TRT1
C1 – Time of Use Energy (Bidirectional Residential)	RT12
B1 – Distribution Entry Service	RT11
B2 – Transmission Entry Service	TRT2

5.2 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.

5.2.1 RT1 – Anytime Energy (Residential)

The tariff structure for distribution includes:

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

The tariff structure for transmission includes:

- 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.

5.2.2 RT2 – Anytime Energy (Business)

The tariff structure for distribution includes:

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

The tariff structure for transmission includes:

- 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

5.2.3 RT3 – Time of Use Energy (Residential)

The tariff structure for distribution includes:

- 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 includes:

- 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.

5.2.4 RT4 – Time of Use Energy (Business)

The tariff structure for distribution includes:

- 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 includes:

- 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.

5.2.5 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%.

5.2.6 RT6 – Low Voltage Metered Demand

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

5.2.7 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.

5.2.8 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 additional cost for usage of the low voltage distribution network.

5.2.9 RT9 – Streetlighting

Streetlights 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 based on burn hours and globe wattage.

The tariff structure for distribution includes:

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

The tariff structure for transmission includes:

- A charge per kWh for calculated energy consumption.

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

5.2.10 RT10 – Unmetered Supplies

Unmetered 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 includes:

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

The tariff structure for transmission includes:

- A charge per kWh for calculated energy consumption.

5.2.11 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 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.

5.3 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.

5.3.1 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 the 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's 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 distribution-connected generators 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.

The transmission component also contains a locational signal. Like for TRT2 customers, there is a monthly penalty for any demand excursion above the DSOC that has not been authorised by System Management.

5.3.2 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 DSOC, in kWs, that reflects their maximum intended export capacity. There is a monthly penalty for any demand excursion above the DSOC that has not been authorised by System Management.

5.4 RT12 – Time of Use Energy (Bidirectional Residential)

The tariff structure for distribution includes:

- 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 includes:

- 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.

6 Derivation of Transmission System Tariff Components

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

6.1 Cost Reflective Network Pricing

6.1.1 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 CRNP 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.

6.1.2 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.

6.1.3 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.

6.2 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.

6.2.1 Transmission Pricing Model

Once Transmission assets are valued and T-price (see below for details) 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.

6.2.2 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.

6.2.3 Use of System (UOS) Prices

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

6.2.3.1. T-Price

Western Power uses T-price to establish the relativity of UOS prices for each exit and entry point. T-price is a modelling tool to allocate network costs using CRNP. 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 all entry and exit points.
- Load flow analysis is carried out so that all network element costs are allocated to each zone substation based on usage of those network elements.
- The costs for all entry and exit points 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.

6.2.3.2. UOS Prices – Exit Points

UOS prices for Exit Points are calculated to recover the UOS for Loads Cost Pool Revenue.

6.2.3.3. UOS Prices – Entry Points

UOS prices for Entry Points are calculated to recover the UOS for Generators Cost Pool Revenue.

6.2.4 Common Service Price for Loads

The Common Service Price is expressed in c/kW/day 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 CMDs (over all Exit points where the charge is applied).

6.2.5 Control System Service Price

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

6.2.5.1. 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 CMDs (over all Exit points where the charge is applied).

6.2.5.2. 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 DSOCs (over all Entry Points where the charge is applied).

6.2.6 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 6.3 for further details).

Table 11 - Transmission Revenue Forecast for 2012/13 ($M Nominal)

	Forecast Total MW	Number Customers	Forecast Transmission Revenue Recovered
TRT1 – Transmission Exit	613	26	33.6
TRT2 – Transmission Entry (includes LV Gens etc.)	6354	29	77.2
RT1 – RT 12 - Distribution Users (Pass Through)	3803	1,309,781	312.2
TOTAL			**423.0**
Forecast over/(under)-recovery			0.5

Note: The standby cost pool and associated revenue has been removed from reference services due to the standby service being provided as a non-reference service.

6.3 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 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 >1 MVA 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, as discussed in section 5. 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 Western Power Network.

6.3.1 Flow Chart

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

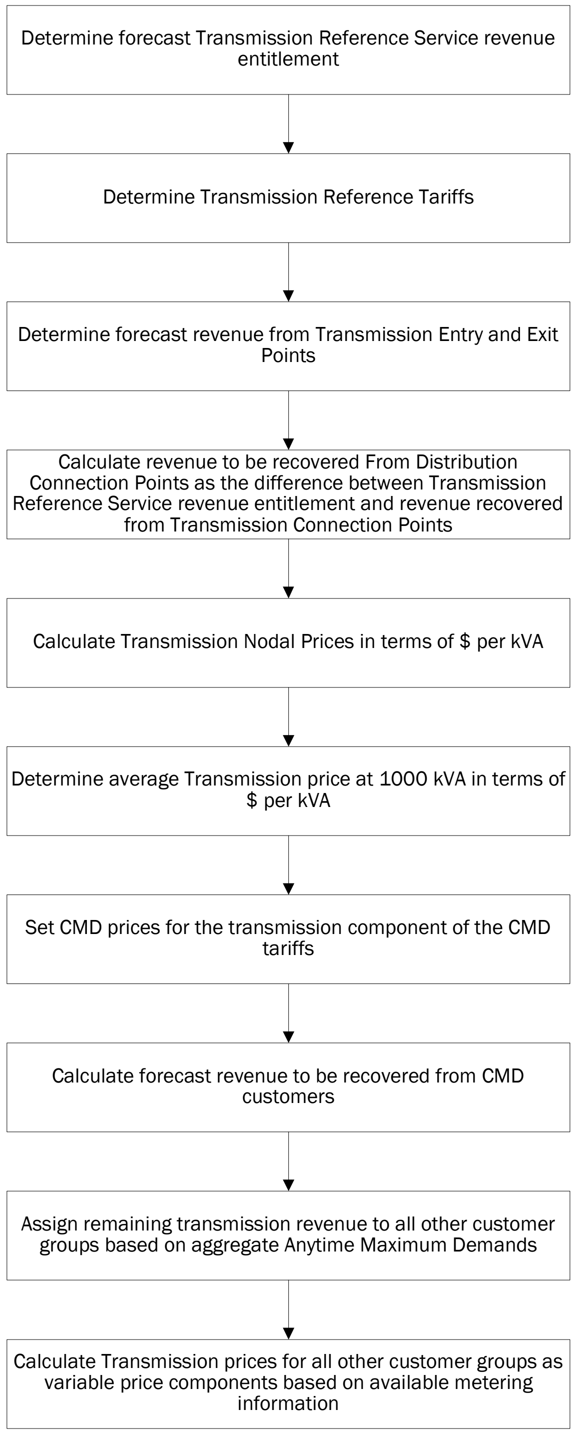

Figure 3 - Derivation of Transmission Tariff Component of Distribution System Flow Chart

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.

6.3.2 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.

6.3.3 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 a number of 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.

Another reason for this approach 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 connection 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.

6.3.4 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

$\text{Price}_{1,000 \text{ to } 7,000}$ = 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 $\text{Price}_{1,000 \text{ to } 7,000}$ 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 kVA) - ($\text{Price}_{\text{At } 1,000}$ * 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. We now have a single unknown ($\text{Price}_{\text{At } 1,000}$) that can now be solved in the above equation which now must be expanded as below.

Original Equation:

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

Expansion of each term:

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

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

$\text{RP}_{\text{Over } 7,000}$ = ∑ 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

$\text{RP}_{1,000 \text{ to } 7,000}$ = ∑ 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

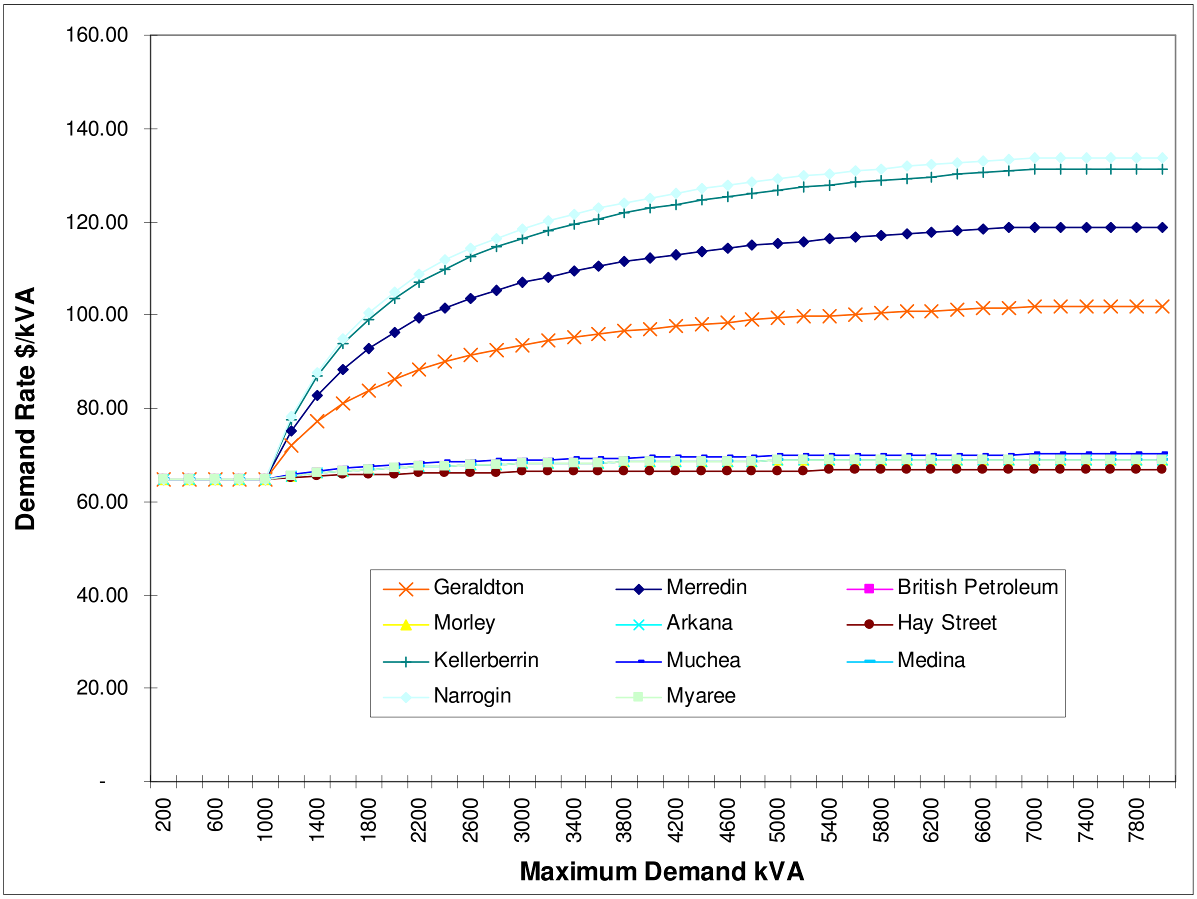

Figure 4 - Rate Blocks Example

6.3.5 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.

6.3.6 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 unmetered 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.

6.3.7 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 2012/13 ($M Nominal)

	kWh	ATMD kVA	Number Customers	Forecast Transmission Revenue Recovered
RT1 - Anytime Energy (Residential)	5,319,275,949	2,385,513	928,361	107.5
RT2 - Anytime Energy (Business)	1,626,702,520	897,863	90,014	39.5
RT3 - Time of Use Energy (Residential)	213,268,785	108,573	24,799	4.6
RT4 - Time of Use Energy (Business)	2,009,149,700	1,513,934	12,687	45.4
RT5 - High Voltage Metered Demand	405,345,690	178,397	184	10.2
RT6 - Low Voltage Metered Demand	1,343,018,790	496,309	2,130	34.2
RT7 - High Voltage Contract Maximum Demand	3,089,046,010	773,644	335	63.0
RT8 - Low Voltage Contract Maximum Demand	239,760,628	77,609	64	5.5
RT9 – Streetlighting	121,595,204	30,107	240,095	1.9
RT10 - Unmetered Supplies	34,479,656	5,480	15,801	0.3
RT11 - Distribution Entry	0	0	21	0.0
RT12 – Time of Use Energy (Bidirectional Residential)	0	0	0	0
TOTAL	**14,401,642,932**	**6,467,428**	**1,314,491**	**312.225**

6.4 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.

7 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 ATMDs.

The Code requires uniform reference tariffs for all users with annual energy demand below 1 MVA, which equates to approximately all but 500 connected to the Western Power Network. 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 TEC through distribution reference tariffs for exit services (Western Power has extended this to include bi-directional services to be consistent with the Code Objective). Section 7.5 details the amounts associated with TEC that are embedded within the distribution reference tariff components.

7.1 Price Setting

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

7.1.1 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	TARIFF COMPONENTS									
	Fixed Component	**Energy Only**	**On Peak Energy**	**Off Peak Energy**	**Annual Metered Demand**	**Off Peak Discount Factor (%)**	**CMD**	**Demand/ Length for ATMD > 1,000 kVA**	**Fixed Metering Component**	**Variable Metering Component**
RT1 - Energy Only (Residential)	✓	✓							✓	✓
RT2 - Energy Only (Business)	✓	✓							✓	✓
RT3 - Time of Use Energy (Residential)	✓		✓	✓					✓	✓
RT4 - Time of Use Energy (Business)	✓		✓	✓					✓	✓
RT5 - HV Metered Demand	✓				✓	✓		✓	✓	
RT6 - LV Metered Demand	✓				✓	✓		✓	✓	
RT7 - HV CMD	✓						✓	✓	✓	
RT8 - LV CMD	✓						✓	✓	✓	
RT9 - Streetlighting	✓	✓								
RT10 – Unmetered	✓	✓								
RT11 - Distribution Entry							✓	✓	✓	
RT12 – Time of Use Energy (Bidirectional Residential)	✓		✓	✓					✓	✓

7.1.2 RT1 and 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.

7.1.3 RT3 and 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 (RT1).

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.

7.1.4 RT5 and 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 Figure 5.

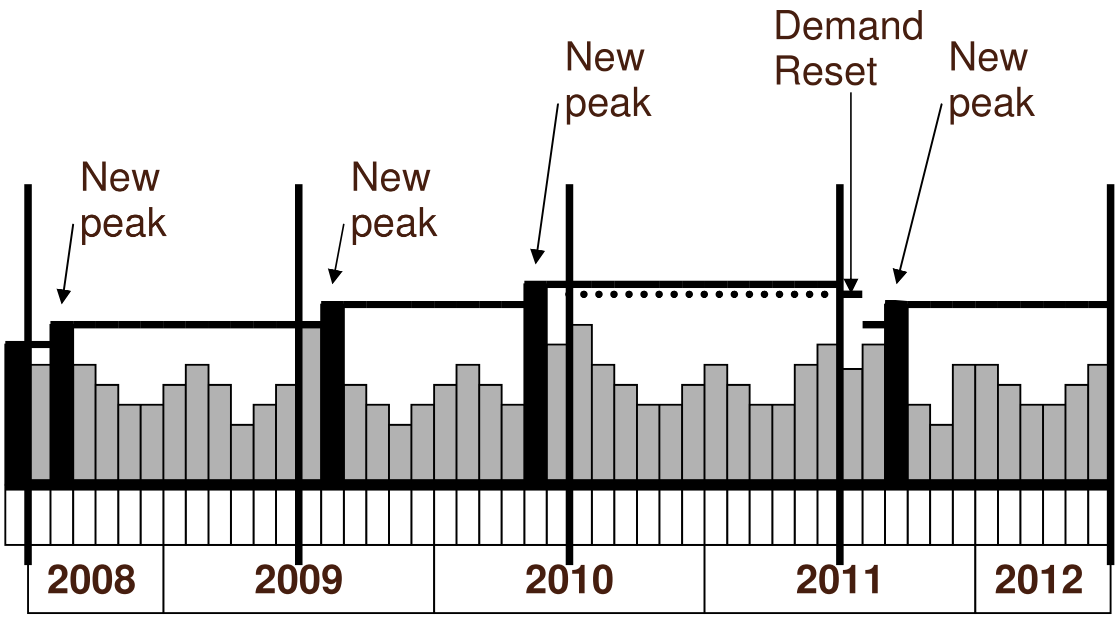

Figure 5 - Rolling Peak Illustration

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.

7.1.5 RT7 and 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, or 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 7.2.

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 7.2.

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.

7.1.6 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 and $ fixed annual charge
TOU Energy	Cents/kWh and $ fixed annual charge
Metered Demand	$ fixed annual charge
CMD	$ fixed annual charge

7.1.7 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.

7.1.8 RT9 - Streetlighting

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 luminaire and is based on the annualised cost of capital and maintenance associated with each.

7.1.9 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.

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

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

The fixed component is set to be the same as the fixed component of the residential energy only tariff (RT1).

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.

7.2 Demonstration of Derivation of Distribution Components of Distribution Reference Tariffs

7.2.1 Demand/Length Graph

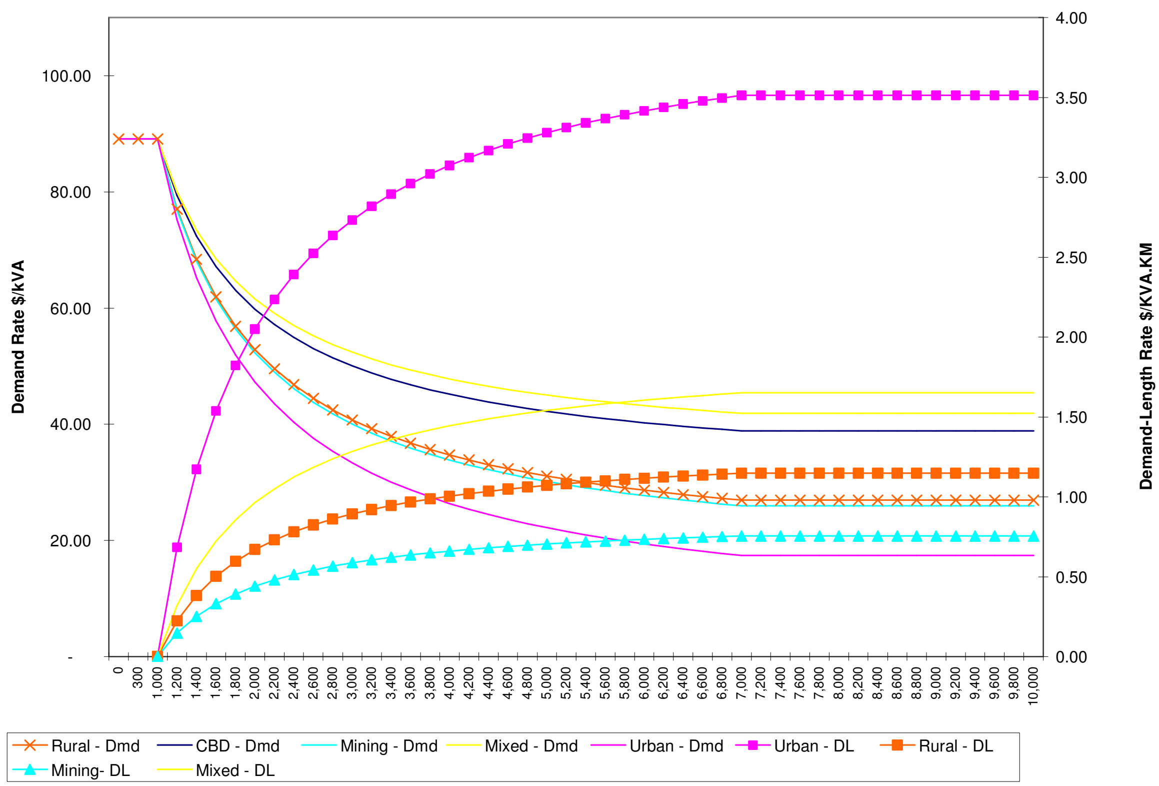

Figure 6 - Demand Length Rates and CMD Rates by Zone

7.2.2 Forecast Tariff 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 2012/13 ($M Nominal)

	kWh	ATMD kVA	Number Customers	Forecast Distribution Revenue Recovered
RT1 - Anytime Energy (Residential)	5,319,275,949	2,385,513	928,361	511.1
RT2 - Anytime Energy (Business)	1,626,702,520	897,863	90,014	159.8
RT3 - Time of Use Energy (Residential)	213,268,785	108,573	24,799	18.4
RT4 - Time of Use Energy (Business)	2,009,149,700	1,513,934	12,687	124.2
RT5 - High Voltage Metered Demand	405,345,690	178,397	184	16.4
RT6 - Low Voltage Metered Demand	1,343,018,790	496,309	2,130	66.9
RT7 - High Voltage Contract Maximum Demand	3,089,046,010	773,644	335	47.2
RT8 - Low Voltage Contract Maximum Demand	239,760,628	77,609	64	8.6
RT9 – Streetlighting	121,595,204	30,107	240,095	32.6
RT10 - Unmetered Supplies	34,479,656	5,480	15,801	3.2
RT11 - Distribution Entry	0	0	21	0.7
RT12 - Time of Use Energy (Bidirectional Residential)	0	0	0	0
TOTAL	**14,401,642,932**	**6,467,428**	**1,314,491**	**989.1**
Forecast over-recovery (compared to Distribution Reference Service Revenue of $989.7m)				**(0.6)**

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

The pricing methods requirement for reference tariffs to be between incremental and stand-alone cost of service provision is set out in section 7.3 (b) of the Code as follows:

> 7.3 Subject to sections 7.5, 7.7 and 7.12[177], the *pricing methods* in an *access arrangement* must have the objectives that:
>
> (a) *reference tariffs* recover the forward-looking efficient costs of providing *reference services*; and
>
> (b) the *reference tariff* applying to a *user*:
>
> (i) at the lower bound, is equal to, or exceeds, the *incremental cost of service provision*; and
>
> (ii) at the upper bound, is equal to, or is less than, the *stand-alone cost of service provision*.

At this stage Western Power does not have approved costs to serve as a basis for setting revenues and prices for 2012/13, and therefore it is difficult to quantitatively demonstrate compliance with section 7.3 (b) of the Code. As a result Western Power has made no attempt to do so in this Price List Information.

However Western Power asserts that the 2012/13 Price List complies with the pricing methods in section 7.3(b) of the Code due to:

1. The 2011/12 Price List complied with section 7.3 (b) of the Code;

2. The 2012/13 Price List increases all distribution tariff components by 13% when compared to the 2011/12 Price List and leaves transmission tariffs as is; and

3. No changes have been proposed to the structure of the reference tariffs.

7.4 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 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, annual price movements are consequently limited within “side constraints” as detailed in the Access Arrangement.

7.5 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 section 7.2 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.

7.5.1 TEC Forecast Revenue

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

Table 15 - TEC Recovered from Distribution Connection Points for 2012/13 ($M Nominal)

	kWh	ATMD kVA	Number Customers	Forecast TEC Recovered
RT1 - Anytime Energy (Residential)	5,319,275,949	2,385,513	928,361	74.7
RT2 - Anytime Energy (Business)	1,626,702,520	897,863	90,014	22.8
RT3 - Time of Use Energy (Residential)	213,268,785	108,573	24,799	2.6
RT4 - Time of Use Energy (Business)	2,009,149,700	1,513,934	12,687	29.9
RT5 - High Voltage Metered Demand	405,345,690	178,397	184	6.3
RT6 - Low Voltage Metered Demand	1,343,018,790	496,309	2,130	20.8
RT7 - High Voltage Contract Maximum Demand	3,089,046,010	773,644	335	6.9
RT8 - Low Voltage Contract Maximum Demand	239,760,628	77,609	64	1.6
RT9 – Streetlighting	121,595,204	30,107	240,095	1.7
RT10 - Unmetered Supplies	34,479,656	5,480	15,801	0.5
RT11 - Distribution Entry	0	0	21	0.0
RT12 - Time of Use Energy (Bidirectional Residential)	0	0	0	0
TOTAL	**14,401,642,932**	**6,467,428**	**1,314,491**	**167.9**

7.5.2 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 16

		Fixed TEC	Variable TEC		
		c/day	c/kWh	On Peak c/kWh	Off Peak c/kWh
Reference tariff 1 - RT1					
	TEC	0.000	1.405	-	-
Reference tariff 2 - RT2					
	TEC	0.000	1.405	-	-
Reference tariff 3 - RT3					
	TEC	0.000	-	2.000	0.572
Reference tariff 4 - RT4					
	TEC	0.000	-	2.000	0.572
Reference tariff 9 – RT9					
	TEC	0.000	1.405	-	-
Reference tariff 10 – RT10					
	TEC	0.000	1.405	-	-

7.5.3 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 17

	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	14.885	0.000	14.885
300 to 1000	4,465.500	14.359	4,465.500	14.359
1000 to 1500	14,516.800	5.223	14,516.800	5.223

7.5.4 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 18

Pricing Zone	RT 7 and 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	7,311.874	-1.219	0.000
Goldfields Mining	7,311.874	-1.219	0.000
Mixed	7,311.874	-1.219	0.000
Rural	7,311.874	-1.219	0.000
Urban	7,311.874	-1.219	0.000

Note: Users with demand greater than 7,000 kVA do not pay TEC. These users can usually choose between being transmission 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 additional 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.

8 Price Changes

The following tables detail the % change in the 2012/13 tariff components when compared to the 2011/12 tariff components.

8.1 Use of System Prices

The % changes in the following table are applicable for reference tariffs: **RT1, RT2, RT3, RT4, RT9, RT10, RT13, RT14, RT15 and RT16**.

Table 19

		Fixed Price	Energy Rates		
		% Change	Anytime % Change	On Peak % Change	Off Peak % Change
Reference tariff 1 - RT1					
	Transmission		0%		
	Distribution	13.31%	13.00%		
	Bundled Tariff	13.31%	9.17%		
	Metering	13.30%	13.00%		
Reference tariff 2 – RT2					
	Transmission		0.00%		
	Distribution	13.31%	13.00%		
	Bundled Tariff	13.31%	9.59%		
	Metering	13.30%	13.00%		
Reference tariff 3 - RT3					
	Transmission			0.00%	0.00%
	Distribution	13.31%		13.00%	13.00%
	Bundled Tariff	13.31%		8.75%	9.02%
	Metering	13.30%		13.00%	13.00%
Reference tariff 4 - RT4					
	Transmission			0.00%	0.00%
	Distribution	13.31%		13.00%	13.00%
	Bundled Tariff	13.31%		9.04%	8.89%
	Metering	13.31%		13.00%	13.00%
Reference tariff 9 – RT9					
	Transmission		0.00%		
	Distribution	13.32%	13.00%		
	Bundled Tariff	13.32%	9.13%		
Reference tariff 10 – RT10					
	Transmission		0.00%		
	Distribution	13.31%	13.00%		
	Bundled Tariff	13.31%	10.60%		

8.2 Streetlight Asset Prices

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

Table 20

Light Specification	Annual Charge % Change
42W CFL SE	13.3%
42W CFL BH	13.3%
42W CFL KN	13.3%
50W MV	13.3%

70W MH	13.3%
70W HPS	13.3%
80W MV	13.3%
125W MV	13.3%
150W MH	13.3%
150W HPS	13.3%
250W MH	13.3%
250W HPS	13.3%
250W MV	13.3%
400W MV	13.3%

8.3 Metered Demand Prices

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

Table 21

	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		0.00%	13.3%	13.3%	13.3%	7.6%
300 to 1000	0.00%	0.00%	13.3%	13.3%	7.6%	7.7%
1000 to 1500	0.00%	0.00%	13.3%	13.3%	7.7%	6.6%

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

Table 22

	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		0.00%	13.3%	13.3%	13.3%	8.0%
300 to 1000	0.00%	0.00%	13.3%	13.3%	8.2%	8.2%
1000 to 1500	0.00%	0.00%	13.3%	13.3%	8.2%	7.7%

8.4 Demand Prices

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

Table 23

Zone Substation	TNI	Pricing Zone	Transmission			Distribution			Bundled		
			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)	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)	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)
Cook Street	WCKT	CBD	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	3.8%	4.5%
Forrest Avenue	WFRT	CBD	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	3.8%	4.5%
Hay Street	WHAY	CBD	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	3.8%	4.5%
Milligan Street	WMIL	CBD	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	3.8%	4.5%
Wellington Street	WWNT	CBD	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	3.8%	4.5%
Black Flag	WBKF	Goldfields Mining	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	1.3%	2.1%
Boulder	WBLD	Goldfields Mining	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	1.3%	2.2%
Bounty	WBNY	Goldfields Mining	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.7%	1.3%
West Kalgoorlie	WWKT	Goldfields Mining	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	1.5%	2.4%
Albany	WALB	Mixed	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	2.7%	3.4%
Boddington	WBOD	Mixed	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	4.4%	5.0%
Bunbury Harbour	WBUH	Mixed	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	4.4%	5.0%
Busselton	WBSN	Mixed	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	3.0%	3.7%
Byford	WBYF	Mixed	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	4.3%	4.9%
Capel	WCAP	Mixed	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	3.4%	4.1%
Chapman	WCPN	Mixed	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	2.6%	3.2%
Darlington	WDTN	Mixed	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	4.0%	4.7%
Durlacher Street	WDUR	Mixed	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	2.9%	3.5%
Eneabba	WENB	Mixed	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	3.0%	3.6%
Geraldton	WGTN	Mixed	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	2.9%	3.5%
Marriott Road	WMRR	Mixed	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	4.4%	5.0%
Muchea	WMUC	Mixed	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	4.0%	4.6%
Northam	WNOR	Mixed	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	3.0%	3.7%
Picton	WPIC	Mixed	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	4.0%	4.7%
Rangeway	WRAN	Mixed	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	2.9%	3.5%
Sawyers Valley	WSVL	Mixed	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	3.0%	3.6%
Yanchep	WYCP	Mixed	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	4.1%	4.7%
Yilgarn	WYLN	Mixed	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	2.8%	3.5%
Baandee	WBDE	Rural	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	1.2%	2.0%
Beenup	WBNP	Rural	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	1.2%	2.0%
Bridgetown	WBTN	Rural	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	1.9%	2.9%
Carrabin	WCAR	Rural	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	1.1%	1.8%
Collie	WCOE	Rural	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	1.5%	2.5%
Coolup	WCLP	Rural	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	1.5%	2.3%
Cunderdin	WCUN	Rural	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	1.3%	2.1%
Katanning	WKAT	Rural	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	1.5%	2.4%
Kellerberrin	WKEL	Rural	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	1.2%	2.0%

Zone Substation	TNI	Pricing Zone	Transmission			Distribution			Bundled		
			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)	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)	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)
Kojonup	WKOJ	Rural	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	2.2%	3.3%
Kondinin	WKDN	Rural	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	1.9%	3.0%
Manjimup	WMJP	Rural	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	1.9%	2.9%
Margaret River	WMRV	Rural	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	1.3%	2.1%
Merredin	WMER	Rural	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	1.4%	2.2%
Mirambeena	WMBN	Rural	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	3.2%	4.3%
Moora	WMOR	Rural	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	1.8%	2.7%
Mount Barker	WMBR	Rural	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	1.5%	2.5%
Narrogin	WNGN	Rural	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	1.2%	2.0%
Pinjarra	WPNJ	Rural	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	2.4%	3.5%
Regans	WRGN	Rural	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	1.8%	2.7%
Three Springs	WTSG	Rural	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	1.7%	2.7%
Wagerup	WWGP	Rural	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	2.5%	3.7%
Wagin	WWAG	Rural	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	1.6%	2.5%
Wundowie	WWUN	Rural	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	1.6%	2.5%
Yerbillon	WYER	Rural	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	1.1%	1.8%
Amherst	WAMT	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Arkana	WARK	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Australian Paper Mills	WAPM	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Beechboro	WBCH	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Belmont	WBEL	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Bentley	WBTY	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Bibra Lake	WBIB	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
British Petroleum	WBPM	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Canning Vale	WCVE	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Clarence Street	WCLN	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Clarkson	WCKN	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Cockburn Cement	WCCT	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Collier	WCOL	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Cottesloe	WCTE	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Edmund Street	WEDD	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Forrestfield	WFFD	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Gosnells	WGNL	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Hadfields	WHFS	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Hazelmere	WHZM	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Henley Brook	WHBK	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Herdsman Parade	WHEP	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Joel Terrace	WJTE	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Joondalup	WJDP	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Joondanna	WJDA	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Kalamunda	WKDA	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%

Zone Substation	TNI	Pricing Zone	Transmission			Distribution			Bundled		
			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)	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)	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)
Kambalda	WKBA	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.5%	1.6%
Kewdale	WKDL	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Landsdale	WLDE	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Malaga	WMLG	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Mandurah	WMHA	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Manning Street	WMAG	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Mason Road	WMSR	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Meadow Springs	WMSS	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Medical Centre	WMCR	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Medina	WMED	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Midland Junction	WMJX	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Morley	WMOY	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Mullaloo	WMUL	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Mundaring Weir	WMWR	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Munday	WMDY	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Murdoch	WMUR	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Myaree	WMYR	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Nedlands	WNED	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
North Beach	WNBH	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
North Fremantle	WNFL	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
North Perth	WNPH	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
OConnor	WOCN	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Osborne Park	WOPK	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Padbury	WPBY	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Piccadilly	WPCY	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.5%	1.6%
Riverton	WRTN	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Rivervale	WRVE	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Rockingham	WROH	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Shenton Park	WSPA	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Sth Ftle Power Station	WSFT	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Southern River	WSNR	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Tate Street	WTTS	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
University	WUNI	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Victoria Park	WVPA	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Waikiki	WWAI	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Wangara	WWGA	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Wanneroo	WWNO	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Welshpool	WWEL	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Wembley Downs	WWDN	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Willeton	WWLN	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%
Yokine	WYKE	Urban	0.00%	0.00%	0.00%	13.3%	13.3%	13.3%	7.3%	0.9%	2.4%

8.5 Demand Length Prices

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

Table 24

	Demand-Length Charge	
Pricing Zone	**For kVA >1000 and first 10 km length % Change**	**For kVA >1000 and length in excess of 10 km % Change**
CBD	N/A	N/A
Urban	13.3%	13.3%
Mining	13.3%	13.3%
Mixed	13.3%	13.3%
Rural	13.3%	13.3%

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

Table 25

	Demand-Length Charge	
Pricing Zone	**For first 10 km length % Change**	**For length in excess of 10 km % Change**
CBD	N/A	N/A
Urban	13.3%	13.3%
Mining	13.3%	13.3%
Mixed	13.3%	13.3%
Rural	13.3%	13.3%

8.6 Metering Prices

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

Table 26

Metering Equipment Funding	Voltage	% Change
Western Power funded	High Voltage (6.6 kV or higher)	13.3%
	Low voltage (415 volts or less)	13.3%
Customer funded	High Voltage (6.6 kV or higher)	13.3%
	Low Voltage (415 volts or less)	13.3%

8.7 Administration Prices

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

Table 27

Peak Demand	% Change
>=7,000 kVA	13.0%
<7,000 kVA	13.0%

8.8 Low Voltage Prices

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

Table 28

Category	% Change
Fixed	13.3%
Demand	13.3%

8.9 Connection Prices

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

Table 29

	Connection Price % Change
Connection Price	0%

8.10 Transmission Use of System Prices

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

Table 30

Substation	TNI	Use of System Price % Change
Albany	WALB	0%
Alcoa Pinjarra	WAPJ	0%
Amherst	WAMT	0%
Arkana	WARK	0%
Australian Fused Materials	WAFM	0%
Australian Paper Mills	WAPM	0%
Baandee (WC)	WBDE	0%
Beckenham	WBEC	0%
Beechboro	WBCH	0%
Beenup	WBNP	0%
Belmont	WBEL	0%
Bentley	WBTY	0%
Bibra Lake	WBIB	0%
Binningup Desalination Plant	WBDP	0%
Black Flag	WBKF	0%
Boddington Gold	WBOD	0%
Boddington (Local)	WABD	0%
Boddington Reynolds	WRBD	0%
Boulder	WBLD	0%
Bounty	WBNY	0%
Bridgetown	WBTN	0%
British Petroleum	WBPM	0%
Broken Hill Kwinana	WBHK	0%
Bunbury Harbour	WBUH	0%
Busselton	WBSN	0%
Byford	WBYF	0%
Canning Vale	WCVE	0%

Substation	TNI	Use of System Price % Change
Capel	WCAP	0%
Carrabin	WCAR	0%
Cataby Kerr McGee	WKMC	0%
Chapman	WCPN	0%
Clarence Street	WCLN	0%
Clarkson	WCKN	0%
Cockburn Cement	WCCT	0%
Cockburn Cement Ltd	WCCL	0%
Collie	WCOE	0%
Collier	WCOL	0%
Cook Street	WCKT	0%
Coolup	WCLP	0%
Cottesloe	WCTE	0%
Cunderdin	WCUN	0%
Darlington	WDTN	0%
Edgewater	WEDG	0%
Edmund Street	WEDD	0%
Eneabba	WENB	0%
Forrest Ave	WFRT	0%
Forrestfield	WFFD	0%
Geraldton	WGTN	0%
Glen Iris	WGNI	0%
Golden Grove	WGGV	0%
Gosnells	WGNL	0%
Hadfields	WHFS	0%
Hay Street	WHAY	0%
Hazelmere	WHZM	0%
Henley Brook	WHBK	0%
Herdsman Parade	WHEP	0%
Joel Terrace	WJTE	0%
Joondalup	WJDP	0%
Kalamunda	WKDA	0%
Katanning	WKAT	0%
Kellerberrin	WKEL	0%
Kojonup	WKOJ	0%
Kondinin	WKDN	0%
Kwinana Alcoa	WAKW	0%
Kwinana Desalination Plant	WKDP	0%
Kwinana PWS	WKPS	0%
Landsdale	WLDE	0%
Malaga	WMLG	0%
Mandurah	WMHA	0%
Manjimup	WMJP	0%
Manning Street	WMAG	0%
Margaret River	WMRV	0%
Marriott Road Barrack Silicon Smelter	WBSI	0%
Marriott Road (Local)	WLMR	0%
Mason Road	WMSR	0%
Mason Road CSBP	WCBP	0%
Mason Road Hismelt	WHIS	0%

Substation	TNI	Use of System Price % Change
Mason Road Kerr McGee	WKMK	0%
Meadow Springs	WMSS	0%
Medical Centre	WMCR	0%
Medina	WMED	0%
Merredin 66kV	WMER	0%
Midland Junction	WMJX	0%
Milligan Street	WMIL	0%
Moora	WMOR	0%
Morley	WMOY	0%
Mt Barker	WMBR	0%
Muchea Kerr McGee	WKMM	0%
Muchea (Local)	WLMC	0%
Muja PWS	WMPS	0%
Mullaloo	WMUL	0%
Murdoch	WMUR	0%
Mundaring Weir	WMWR	0%
Myaree	WMYR	0%
Narrogin	WNGN	0%
Nedlands	WNED	0%
North Beach	WNBH	0%
North Fremantle	WNFL	0%
North Perth	WNPH	0%
Northam	WNOR	0%
O'Connor	WOCN	0%
Osborne Park	WOPK	0%
Padbury	WPBY	0%
Parkeston	WPRK	0%
Parklands	WPLD	0%
Piccadilly	WPCY	0%
Picton 66kv	WPIC	0%
Pinjarra	WPNJ	0%
Rangeway	WRAN	0%
Regans	WRGN	0%
Riverton	WRTN	0%
Rivervale	WRVE	0%
Rockingham	WROH	0%
Sawyers Valley	WSVL	0%
Shenton Park	WSPA	0%
Southern River	WSNR	0%
South Fremantle 22kV	WSFT	0%
Summer St	WSUM	0%
Tate Street	WTTS	0%
Three Springs	WTSG	0%
Tomlinson Street	WTLN	0%
University	WUNI	0%
Victoria Park	WVPA	0%
Wagerup	WWGP	0%
Wagin	WWAG	0%
Waikiki	WWAI	0%
Wangara	WWGA	0%

Substation	TNI	Use of System Price % Change
Wanneroo	WWNO	0%
WEB Grating	WWEB	0%
Wellington Street	WWNT	0%
Welshpool	WWEL	0%
Wembley Downs	WWDN	0%
West Kalgoorlie	WWKT	0%
Western Collieries	WWCL	0%
Western Mining	WWMG	0%
Westralian Sands	WWSD	0%
Willeton	WWLN	0%
Worsley	WWOR	0%
Wundowie	WWUN	0%
Yanchep	WYCP	0%
Yerbillon	WYER	0%
Yilgarn	WYLN	0%
Yokine	WYKE	0%

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

Table 31

Substation	TNI	Use of System % Change
Albany Windfarm	WALB	0%
Boulder	WBLD	0%
Bluewaters	WBWP	0%
Cockburn PWS	WCKB	0%
Collgar	WCGW	0%
Collie PWS	WCPS	0%
Emu Downs	WEMD	0%
Geraldton GT	WGTN	0%
Kemerton PWS	WKEM	0%
Kwinana Alcoa	WAKW	0%
Kwinana Donaldson Road (Western Energy)	WKND	0%
Kwinana PWS	WKPS	0%
Landweir (Alinta)	WLWT	0%
Mason Road	WMSR	0%
Mason Road Hismelt	WHIS	0%
Muja PWS	WMPS	0%
Mungarra GTs	WMGA	0%
Newgen Kwinana	WNGK	0%
Newgen Neerabup	WGNN	0%
Oakley (Alinta)	WOLY	0%
Parkeston	WPKS	0%
Pinjar GTs	WPJR	0%
Alcoa Pinjarra	WAPJ	0%
Tiwest GT	WKMK	0%
Wagerup Alcoa	WAWG	0%
Walkaway Windfarm	WWWF	0%
West Kalgoorlie GTs	WWKT	0%

Substation	TNI	Use of System % Change
Worsley	WWOR	0%

8.11 Common Service Prices

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

Table 32

	Common Service Price % Change
Common Service Price	0%

8.12 Control System Service Prices

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

Table 33

	Price % Change
Control System Service Price (Generators)	0%

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

Table 34

	Price % Change
Control System Service Price (Loads)	0%

8.13 Metering Prices

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

Table 35

	% Change
Transmission Metering	0%

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 CMD weighted average TUOS price adjustment for all other load or generator transmission nodes (as applicable).

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 2.39% of the full capital cost. This percentage is based on the average of the ratio of the forecast Operations and Maintenance cost and the GODV of the transmission network over the Access Arrangement period. 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 Western Power Network. 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.