2023/24 Price List

Public

26 April 2023

westernpower

An appropriate citation for this paper is:

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1. Introduction

1.1 Overview

This document details Western Power's Price List for the pricing year commencing on 1 July 2023 and ending on 30 June 2024, which represents the second pricing year of Western Power's fifth access arrangement (AA5) period. We submit it for review and approval by the ERA as required by clause 8.1(a) of Chapter 8 of the *Electricity Networks Access Code 2004* (Access Code).

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 period covered by this price list and the remainder within a previous or subsequent period 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.

1.2 Key reforms

This document should be read in conjunction with Western Power's Reference Tariff Change Forecast and Tariff Structure Statement, as approved by the ERA as part of the approved AA5 access arrangement[1]; and published on Western Power's website in accordance with section 8.15 of the Access Code on 11 April 2023.[2]

The key pricing reforms adopted for the 2023-27 access arrangement period are:

- Introduction of new super off-peak time of use energy and demand reference tariffs for residential (RT35 and RT37) and small business customers (RT34 and RT36) to encourage customers to shift their consumption to the middle of the day when PV generation is plentiful.
- Introduction of new reference tariffs for public Electric Vehicle charging stations (RT40 and RT41).
- Introduction of new reference tariffs for grid-connected distribution (RT38 and RT39) and transmission voltage level storage (TRT3).
- Closure of the non-cost reflective time of use tariffs (introduced during AA4) to new customers.

1.3 Structure of this document

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

Section 3 outlines how Western Power applies reference tariffs to non-reference services.

Section 4 provides an overview of how Western Power applies bundled prices to reference tariffs and the application of reference tariffs to exit and bidirectional connection points.

Sections 5, and 6 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.

[1] The AA5 final decision was published on the ERA's website on 31 March 2023 and can be found here: https://www.erawa.com.au/AA5.

[2] The TSS documents can be found at, https://www.westernpower.com.au/about/regulation/network-access-prices/.

Section 8 details the prices that are required to calculate the charges.

Section 9 details various fees that apply under the Applications and Queuing Policy.

Appendix A sets out Western Power's compliance with Chapter's 7 and 8 of the Access Code, including ensuring Western Power's reference tariffs comply with the revenue and pricing principles.

Appendix B sets out the policy for the price setting of new transmission nodes for this access arrangement.

1.4 Revenue outcomes in 2023-24

1.4.1 Revenue targets for 2023-24

The following section details the calculation of the maximum total network revenue target (TNR_t) for Western Power's Transmission and Distribution networks.

TNR_t is determined as follows:

$$TNR_t = NR_t + TEC_t + DTEC_t$$

where:

TNR_t is the maximum total network revenue target services revenue for each financial year, t, of this access arrangement period

NR_t is the annual revenue target services revenue in financial year t

TEC_t is any cost incurred for the financial year t as a result of the tariff equalisation contribution in accordance with section 6.37A of the Code.

$DTEC_t$ is an adjustment for any shortfall or over recovery of actual distribution system revenue compared to TEC_t in preceding years and is calculated in accordance with section 5.7.4 of the access arrangement contract.

$DTEC_t$ is determined as follows:

$$DTEC_t = (FTEC_{t-2} - ATEC_{t-2}) * (1 + WACC_t) * (1 + WACC_{t-1}) + (TEC_{t-1} - FTEC_{t-1}) * (1 + WACC_t)$$

where:

$ATEC_t$ is the actual tariff equalisation contribution revenue received in financial year t.

$FTEC_t$ is the forecast of tariff equalisation contribution revenue to be received in financial year t.

TEC_t is the amount of tariff equalisation contribution to be recovered in a financial year t as gazetted.

$WACC_t$ is the weighted average cost of capital in year t for the Western Power Network as detailed in section 5.4 of the access arrangement contact, on a post-tax real basis.

Table 1.1 – Maximum total network revenue target for 2023-24 ($M real as at 30 June 2022)

Maximum total target revenue	2023-24
NR_t	1,638
TEC_t	173

Maximum total target revenue	2023-24
$DTEC_t$	-4
TNR_t	1,807

The total bundled system cost of supply cost pools and tariffs require the reference service revenue as an input in nominal terms. The following table details the bundled reference service revenue in nominal terms (please see section 1.4.2 for details of the inflation factor used).

Table 1.2 - Total target revenue for 2023-24 ($M)

Transmission Revenue	Revenue (Real)	Revenue (Nominal)
Target Revenue ($NR_{2023-24}$)	1,468	1,807

1.4.2 Derivation of Inflation Factor

In sections 1.4.1 and Table 1.2 Western Power has inflated the reference service revenue from real terms to nominal terms by using inflation in accordance with section 5.7.4 of the *access arrangement contract*.

Table 1.3- Derivation of 2023-24 Inflation Factor

December 2020 – December 2021 – Actual	3.50%
December 2021 – December 2022 – Actual	7.80%
Derived Inflation Factor	1.116

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 2023-24 Price List and the 2021 demand, customer and energy forecasts as required by the *access arrangement contract*.

Table 1.4 – Bundled reference service revenue recovered from distribution and transmission connection points for 2023-24 ($M nominal)

Reference tariff	MWh	Customer numbers	Forecast bundled revenue recovered
RT1 – Anytime Energy (Residential)	1,753,990	287,519	265.03
RT2 – Anytime Energy (Business)	322,916	33,907	62.19
RT3 – Time of Use Energy (Residential)^	30,676	4,032	4.64
RT4 – Time of Use Energy (Business)^	101,229	3,056	14.68
RT5 – High Voltage Metered Demand	669,767	341	47.52
RT6 – Low Voltage Metered Demand	1,694,095	3,662	129.35
RT7 – High Voltage Contract Maximum Demand	3,343,382	344	172.47

Reference tariff	MWh	Customer numbers	Forecast bundled revenue recovered
RT8 – Low Voltage Contract Maximum Demand	239,283	86	24.59
RT9 – Streetlighting	138,422	293,180	62.08
RT10 – Unmetered Supplies	46,854	19,811	6.62
RT11 – Distribution Entry	197	25	4.97
RT13 – Anytime Energy (Residential) Bi-directional	961,201	144,862	140.32
RT14 – Anytime Energy (Business) Bi-directional	46,374	1,400	6.48
RT15 – Time of Use (Residential) Bi-directional^	30,320	8,241	6.18
RT16 – Time of Use (Business) Bi-directional^	20,769	627	3.19
RT17 – Time of Use Energy (Residential)*	730,281	196,408	139.69
RT18 – Time of Use Energy (Business)*	1,399,423	42,247	199.53
RT19 – Time of Use Demand (Residential)*	1,607	249	0.29
RT20 – Time of Use Demand (Business)*	209,944	6,338	47.54
RT21 – Multi Part Time of Use Energy (Residential)*	1,210,348	327,817	233.75
RT22 – Multi Part Time of Use Energy (Business)*	9,639	291	1.38
RT34 – Super Off-peak Time of Use Energy (Business)**	75,779	10,910	15.33
RT35 – Super Off-peal Time of Use Energy (Residential)**	430,597	118,527	83.41
RT36 – Super Off-peak Time of Use Demand (Business)**	61,383	1,853	11.24
RT37 – Super Off-peak Time of Use Demand (Residential)**	56,323	15,504	13.39
RT38 – Low Voltage Distribution Storage**	0	1	1.05
RT39 – High Voltage Distribution Storage**	0	1	1.05
RT40 – Low Voltage Electric Vehicle Charging**	175	10	0.09
RT41 – High Voltage Electric Vehicle Charging**	35	2	0.06
Total Bundled Target Revenue from distribution customers	**13,585,008**	**1,521,253**	**1,698.13**
TRT1 - Transmission exit	838	30	49
TRT2 - Transmission entry	5,654	26	59
TRT3 - Transmission storage**	0	0	1
Total Bundled Target Revenue from transmission customers	**6,492**	**56**	**108.51**
Total Bundled Target Revenue	**13,591,500**	**1,521,309**	**1,806.63**

Note: ^ denotes reference tariffs that were closed to new customer nominations on 1 July 2019.
* denotes reference tariffs that will be closed to new customer nominations from 1 July 2023.
** denotes reference tariffs introduced in AA5 and available from 1 July 2023.

1.6 Reference tariff change forecast

1.6.1 Expected price movements over AA5 period

- As set out in the Reference Tariff Change Forecast documentation, Western Power considers the movement in reference tariffs and the components of reference tariffs over AA5 will generally comply with the following:
  - The current on-peak prices are above our estimates of the long run marginal cost, but we will transition to efficient (lower) peak prices gradually over time.
  - Careful consideration of the extent to which there is any difference between the level of revenue currently recovered from each reference tariff and the efficient target for that reference tariff and will make any adjustments gradually over time to avoid price shocks and provide end-users and stakeholders an opportunity to prepare for arriving at the efficient cost allocation in the future.
  - We will endeavour to limit the increase in the average price of a tariff to no more than two per cent above the change that is required to recover target revenue.
- For residential reference tariffs, Western Power intends to:
  - set consistent fixed charges across all residential reference tariffs;
  - endeavour to increase fixed charges only for residential end-users in 2023-24 and 2024-25 broadly in line with the increase in target revenue in those years and then remain relatively flat in nominal terms for the remainder of AA5; and
  - moderate the extent of rebalancing over the AA5 period so that the increase in residential fixed charges is no more than two per cent above the weighted average change in revenue to be recovered from distribution reference tariffs each year.
- For the new super off-peak tariffs, Western Power notes that a consequence of recovering less of its costs in the middle of the day – due to a near zero super off-peak price – is that the off-peak, shoulder and on-peak prices are slightly higher, when compared to similar tariffs that do not have a super off-peak period. This will ensure we can still recover the total efficient costs of providing services to end-users on the super off-peak tariffs and assist in retaining a sufficiently strong price differential between the super off-peak periods and other variable prices. Western Power considers this will avoid the need for further large increases in fixed charges.

1.6.2 Reference tariff change forecast

Overview

Table 1.5 provides an updated representation of the reference tariff change forecast consistent with the access arrangement. In producing this table, Western Power has considered the expected pricing movements outlined above and the following principles:

- Maintain uniform fixed charges for all residential tariffs, aligned with the access arrangement.
- Increase grandfathered time of use variable charges to cost reflective levels for the FY24 price list, aligned with the access arrangement.
- Fully recover the approved target revenue in each pricing year with gradual price paths toward cost reflectivity over the remaining four pricing years of the access arrangement.

Table 1.5 – Updated reference tariff change forecast updated for the FY24 price list for all AA5 years

Tariff	Service	Average price change 22-23	Average price change 23-24	Average price change 24-25	Average price change 25-26	Average price change 26-27
RT1	A1 – Anytime Energy (Residential) Exit Service	-	1.42%	2.74%	1.21%	1.17%
RT2	A2 – Anytime Energy (Business) Exit Service	-	2.83%	2.51%	1.04%	1.04%
RT3	A3 – Time of Use Energy (Residential) Exit Service	-	13.66%	11.94%	10.86%	11.13%
RT4	A4 – Time of Use Energy (Business) Exit Service	-	13.54%	12.28%	11.08%	11.11%
RT5	A5 – High Voltage Metered Demand Exit Service or C5 Bi-directional Service	-	3.55%	0.05%	0.05%	0.05%
RT6	A6 – Low Voltage Metered Demand Exit Service or Bi-directional Service	-	3.60%	0.20%	0.10%	0.29%
RT7	A7 – High Voltage Contract Maximum Demand Exit Service or C7 Bi-directional Service	-	2.78%	0.42%	0.01%	0.87%
RT8	A8 – Low Voltage Contract Maximum Demand Exit Service or Bi-directional Service	-	3.61%	1.01%	0.02%	1.98%
RT9	A9 – Streetlighting Exit Service	-	43.85%	2.31%	3.29%	3.34%
RT10	A10 – Unmetered Supplies Exit Service	-	4.00%	2.00%	2.00%	2.00%
RT11	B1 – Distribution Entry Service	-	7.16%	2.37%	0.70%	1.16%
RT13	C1 – Anytime Energy (Residential) Bi-directional Service	-	1.19%	2.60%	1.15%	1.08%
RT14	C2 – Anytime Energy (Business) Bi-directional Service	-	0.80%	1.01%	0.43%	0.44%
RT15	C3 – Time of Use (Residential) Bi-directional Service	-	12.41%	10.71%	9.10%	9.45%
RT16	C4 – Time of Use (Business) Bi-directional Service RT16	-	13.77%	12.62%	11.50%	11.39%
RT17	A12 – 3 Part Time of Use Energy (Residential) Exit Service or C9 Bi-directional Service	-	10.64%	11.69%	10.17%	10.64%
RT18	A13 – 3 Part Time of Use Energy (Business) Exit Service or C10 Bi-directional Service	-	14.39%	16.19%	15.50%	15.60%
RT19	A14 – 3 Part Time of Use Demand (Residential) Exit Service or C11 Bi-directional Service	-	11.93%	7.03%	5.79%	5.80%
RT20	A15 – 3 Part Time of Use Demand (Business) Exit Service or C12 Bi-directional Service	-	11.60%	11.47%	10.80%	10.75%
RT21	A16 – Multi Part Time of Use Energy (Residential) Exit Service or C13 Bi-directional Service	-	12.99%	11.26%	9.69%	10.11%

Tariff	Service	Average price change 22-23	Average price change 23-24	Average price change 24-25	Average price change 25-26	Average price change 26-27
RT22	A17 – Multi Part Time of Use Energy (Business) Exit Service C14 or Bi-directional Service	-	13.58%	15.47%	14.81%	14.90%
RT34	A19 – Super Off-peak Energy (Business) Exit Service or – C17 Bidirectional service	-	-	3.50%	2.00%	1.37%
RT35	A18 – Super Off-peak Energy (Residential) Exit Service or C16 – Bidirectional Service	-	-	3.80%	2.24%	1.49%
RT36	A21 – Super Off-peak Demand (Business) Exit Service or C19 – Bidirectional Service	-	-	1.73%	1.66%	0.65%
RT37	A20 – Super Off-peak Demand (Residential) Exit Service or C18 – Bidirectional Service	-	-	3.18%	2.10%	1.24%
RT38	C23 – LV Distribution Storage Bidirectional Service	-	-	5.50%	5.50%	5.50%
RT39	C24 – LV Distribution Storage Bidirectional Service	-	-	6.00%	5.50%	5.50%
RT40	A22 – LV EV Charging Exit Service	-	-	1.73%	1.66%	0.65%
RT41	A23 – HV EV Charging Exit Service	-	-	1.73%	1.66%	0.65%
Distribution Connected Customers		**-**	**7.41%**	**6.10%**	**5.32%**	**5.51%**
TRT1	A11 - Transmission Exit Service	-	7.79%	7.49%	7.50%	7.50%
TRT2	B2 - Transmission Entry Service	-	7.78%	7.48%	7.50%	7.50%
TRT3	C22 - Transmission Storage Service	-	-	7.50%	7.50%	7.50%
Transmission Connected Customers		**-**	**7.71%**	**7.49%**	**7.51%**	**7.51%**
All Tariffs		**-**	**7.43%**	**6.18%**	**5.45%**	**5.64%**

Primary drivers for the updated reference tariff change forecast

The weighted average price change for all tariffs of 7.44% in this price list is due primarily to the following factors:

- Compound inflation (FY23 and FY24) has increased from 6.01% (2.96% x 2.96%) to 11.6% (3.50% x 7.8%), which has increased Target Revenue.
- Distribution level average revenue per customer for demand-based tariffs when updated for actuals is lower than the assumptions that underpinned earlier forecast, because:
  - the demand input assumptions for the Revised Proposal were based on actuals at the end of the AA4 period (June 2022); and
  - whereas for the FY24 price list demand inputs are now based on January 2023 actuals.

This has driven an increase across distribution tariffs to recover the additional target revenue compared with the prices published in the FY23 price list, which was held constant from FY22.

The weighted average price increase for streetlights in FY24 will be 44%. The reasons for this increase are consistent with various directives contained within the approved access arrangement, which include:

- compliance with the cost allocation methodology included in the approved access arrangement to recover streetlighting cost of service only from streetlight tariffs;
- an increase in the RAB over AA4 (from $106 million to $136 million, or 28%);
- an increase in opex costs for streetlights (from $69 million to $102 million, or 48%) due in part to a $4.5m pa step change approved as part of the Draft Decision;
- an increase in WACC in AA5 and increased inflation; and
- the FY23 prices holding constant since FY22.

This is however a one-off increase, as future pricing years over AA5 show more modest increases in the weighted average price changes.

2. References services

The following table details which reference tariff is applicable to each of the reference services.

Table 2.1: Reference services and applicable tariffs and billing codes

Reference service	Reference tariff	MBS Code
A1 – Anytime Energy (Residential) Exit Service	RT1	AER
A2 – Anytime Energy (Business) Exit Service	RT2	AEB
A3 – Time of Use Energy (Residential) Exit Service	RT3	TOUS
A4 – Time of Use Energy (Business) Exit Service	RT4	TOUL
A5 – High Voltage Metered Demand Exit Service C5 – High Voltage Metered Demand Bi-directional Service	RT5	HVMD
A6 – Low Voltage Metered Demand Exit Service C6 – Low Voltage Metered Demand Bi-directional Service	RT6	LVMD
A7 – High Voltage Contract Maximum Demand Exit Service C7 – High Voltage Contract Maximum Demand Bi-directional Service	RT7	HVCMD
A8 – Low Voltage Contract Maximum Demand Exit Service C8 – Low Voltage Contract Maximum Demand Bi-directional Service	RT8	LVCMD
A9 – Streetlighting Exit Service	RT9	SLS
A10 – Unmetered Supplies Exit Service	RT10	UMS
A11 – Transmission Exit Service	TRT1	TREX
B1 – Distribution Entry Service	RT11	DEN
B2 – Transmission Entry Service	TRT2	TREN
C1 – Anytime Energy (Residential) Bi-directional Service	RT13	BAER
C2 – Anytime Energy (Business) Bi-directional Service	RT14	BAEB
C3 – Time of Use (Residential) Bi-directional Service	RT15	BTOUS
C4 – Time of Use (Business) Bi-directional Service	RT16	BTOUL
A12 – 3 Part Time of Use Energy (Residential) Exit Service C9 – 3 Part Time of Use Energy (Residential) Bi-directional Service	RT17	TTOUS
A13 – 3 Part Time of Use Energy (Business) Exit Service C10 – 3 Part Time of Use Energy (Business) Bi-directional Service	RT18	TTOUL
A14 – 3 Part Time of Use Demand (Residential) Exit Service C11 – 3 Part Time of Use Demand (Residential) Bi-directional Service	RT19	DTOUS

Reference service	Reference tariff	MBS Code
A15 – 3 Part Time of Use Demand (Business) Exit Service C12 – 3 Part Time of Use Demand (Business) Bi-directional Service	RT20	DTOUL
A16 – Multi Part Time of Use Energy (Residential) Exit Service C13 – Multi Part Time of Use Energy (Residential) Bi-directional Service	RT21	MTOUS
A17 – Multi Part Time of Use Energy (Business) Exit Service C14 – Multi Part Time of Use Energy (Business) Bi-directional Service	RT22	MTOUL
B3 – Entry Service Facilitating a Distributed Generation or Other Non-Network Solution	RT23	
C15 – Bi-directional Service Facilitating a Distributed Generation or Other Non-Network Solution	RT24	
D1 – Supply Abolishment Service	RT25	
D2 – Capacity Allocation Service	NA[3]	
D6 – Remote Load / Inverter Control Service	RT26	
D8 – Remote De-energise Service	RT28	
D9 – Remote Re-energise Service	RT29	
D10 – Streetlight LED Replacement Service	RT30	
D11 – Site Visit to Support Remote Re-energise Service	RT31	
D12 – Manual De-energise Service	RT32	
D13 – Manual Re-energise Service	RT33	
A19 – Super Off-peak Energy (Business) Exit Service C17 – Super Off-peak Energy (Business) Bi-directional Service	RT34	STOUL
A18 – Super Off-peak Energy (Residential) Exit Service C16 – Super Off-peak Energy (Residential) Exit Service	RT35	STOUS
A21 – Super Off-peak Demand (Business) Exit Service C19 – Super Off-peak Demand (Business) Bi-directional Service	RT36	DSTOUL
A20 – Super Off-peak Demand (Residential) Exit Service C18 – Super Off-peak Demand (Residential) Bi-directional Service	RT37	DSTOUS
C22 – Transmission Storage Service	TRT3	TRST
C23 – Low Voltage Distribution Storage Service	RT38	LVST
C24 – High Voltage Distribution Storage Service	RT39	HVST
A22 – Low Voltage Electric Vehicle Charging Exit Service C20 – Low Voltage Electric Vehicle Charging Bidirectional Service	RT40	LVEV

[3] Applicable Reference Tariff: Any applicable lodgement fees payable in accordance with the Applications and Queuing Policy.

Reference service	Reference tariff	MBS Code
A23 – High Voltage Electric Vehicle Charging Exit Service C21 – High Voltage Electric Vehicle Charging Bidirectional Service	RT41	HVEV

3. Non-reference services

Where Western Power is providing a user a non-reference service at a connection point, the tariff applicable to that non-reference service is the tariff agreed between the user and Western Power.

4. Application of tariffs

4.1 Bundled charges for reference tariffs

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. The bundled charge is the sum of the distribution and transmission components of the charge.

At Western Power's discretion, the charges detailed below may be discounted where there are multiple exit points on the same premises that are configured in a non-standard way. These discounts include, but are not limited to, only charging one administration charge per site.

4.2 Application of reference tariffs to exit and bi-directional points

Reference tariffs RT5 to RT8, RT17 to RT22, and RT34 to RT41 are applicable to reference services at connection points that may be exit points or bi-directional points.

With the exception of the low voltage and high voltage storage tariffs that measure the net consumption of energy transferred into and out of the Western Power network at the connection point, the energy or demand charges are calculated based on energy being transferred out of the network only.

5. Distribution Tariffs

5.1 Anytime energy (RT1 and RT2)

RT1 and RT2 consist of:

a. a fixed use of system charge (detailed in Table 8.1) which is payable each day;

b. a variable use of system charge calculated by multiplying the energy price (detailed in Table 8.1) by the quantity of electricity consumed at an exit point (expressed in kWh); and

c. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day.

5.2 Time of use energy (RT3 and RT4)

RT3 and RT4 consist of:

d. a fixed use of system charge (detailed in Table 8.1) which is payable each day;

e. an on-peak use of system variable charge calculated by multiplying the on-peak energy price (detailed in Table 8.1) by the quantity of on-peak electricity consumed at an exit point (expressed in kWh);

f. an off-peak use of system variable charge calculated by multiplying the off-peak energy price (detailed in Table 8.1) by the quantity of off-peak electricity consumed at an exit point (expressed in kWh); and

g. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day.

Notes:

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

Table 5.1: RT3 and RT4

	Monday – Friday (includes public holidays)			Saturday – Sunday (excludes public holidays)
	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

5.3 High voltage metered demand (RT5)

5.3.1 Tariff calculation

RT5 consists of:

a. a fixed metered demand charge (detailed in Table 8.9) which is payable each day based on the rolling 12-month maximum half-hourly demand at a connection 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 8.9) by the rolling 12-month maximum half-hourly demand at a connection 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 8.12) 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 calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day.

Notes:

1. If a user reduces its rolling 12-month maximum half-hourly demand at a connection point as set out in the process in section 5.3.3 below, then for the purposes of calculating parts a, b and c of the RT5 tariff the 'rolling 12-month maximum half-hourly demand' shall be the reduced amount from the date approved by Western Power.
2. The on and off-peak periods for this tariff are defined in the following table (all times are WST):

Table 5.2: On and off-peak for RT5

Monday – Friday (excludes public holidays)			Saturday – Sunday (includes public holidays)
Off-peak	**On-Peak**	**Off-Peak**	**Off-Peak**
12:00am – 3:00pm	3:00pm – 9:00pm	9:00pm – 12:00am	All times

5.3.2 Discount

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

Where:

MD is the rolling 12-month maximum half-hourly demand at a connection point (expressed in kVA);

DF is the discount factor, which is set at 30%;

$E_{Off\text{-}peak}$ 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.

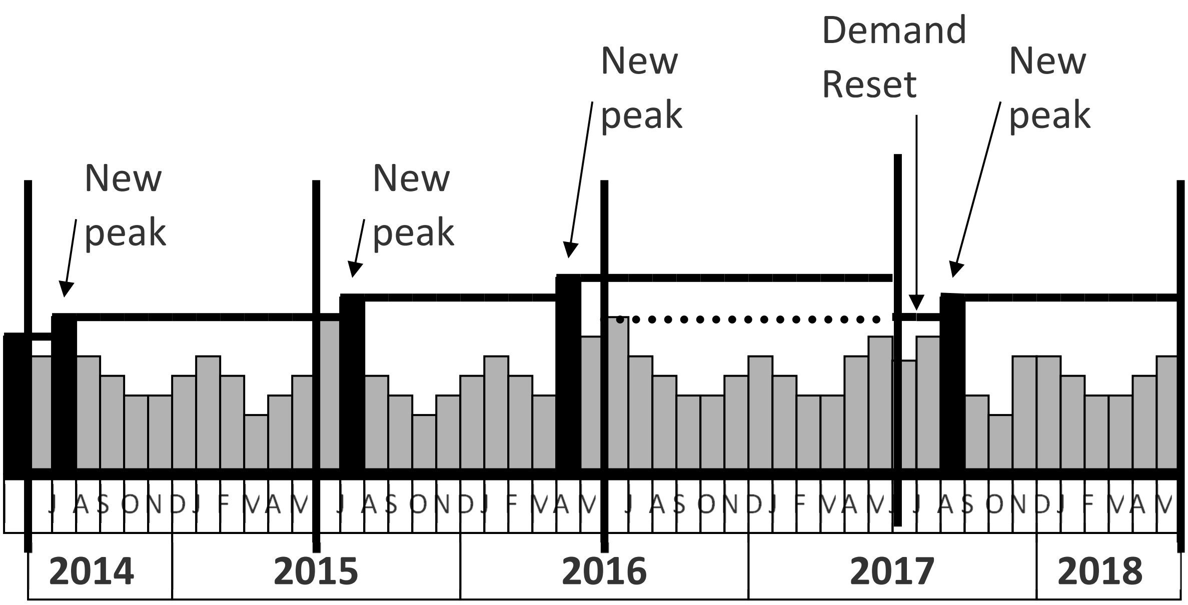
5.3.3 Derivation of rolling 12-month peak

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 5.1.

Figure 5.1: 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.

If a user, or its customer, has implemented initiatives to reduce the future maximum demand on a permanent basis including:

- the implementation of load control, energy efficiency equipment or solutions at the connection point; or
- a fundamental change in the nature of the business or operation conducted at the connection point; or
- a shutdown of the business or operation conducted at the connection point; or
- some other special circumstance or arrangement that reduces the maximum demand at the connection point,

then the user may apply to Western Power for the rolling 12-month period and maximum metered demand to be reset.

The application must include a forecast of maximum demand over the future 12-month period, details of why the user expects the demand will be lower, evidence to support the change and the date the user wishes the revised maximum metered demand to apply from. If Western Power considers, as a reasonable and prudent person and in accordance with good electricity industry practice, that the revised maximum metered demand is reasonable, Western Power must reset the rolling 12-month period and maximum demand in line with the application.

If the actual maximum metered demand exceeds the reset maximum metered demand within 12 months of the reset, an adjustment will be made to charges as though the actual maximum metered demand had applied from the date the reset was implemented.

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 as defined in section 5.3.2 above.

5.4 Low voltage metered demand (RT6)

5.4.1 Tariff calculation

RT6 consists of:

a. a fixed metered demand charge (detailed in Table 8.10) which is payable each day based on the rolling 12-month maximum half-hourly demand at a connection point (expressed in kVA) multiplied by (1-Discount);

b. a variable metered demand charge (detailed in Table 8.10) calculated by multiplying the demand price (in excess of lower threshold) by the rolling 12-month maximum half-hourly demand at a connection 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 8.12) 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 calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day.

Notes:

1. This tariff is similar to RT5 in section 5.3 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 WST):

Table 5.3: On and off-peak for RT6

Monday – Friday (excludes public holidays)			Saturday – Sunday (includes public holidays)
Off-peak	**On-Peak**	**Off-Peak**	**Off-Peak**
12:00am – 3:00pm	3:00pm – 9:00pm	9:00pm – 12:00am	All times

3. If a user reduces its rolling 12-month maximum half-hourly demand at a connection point as set out in the process in section 5.4.3 below, then for the purposes of calculating parts a, b and c of the RT6 tariff the 'rolling 12-month maximum half-hourly demand' shall be the reduced amount from the date approved by Western Power.

5.4.2 Discount

The same formula detailed in section 5.3.2 also applies for RT6.

5.4.3 Derivation of 12-month rolling peak

The same processes detailed in section 5.3.3 also applies for RT6.

5.5 High voltage contract maximum demand (RT7)

5.5.1 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 8.11) which is payable each day; plus
   ii. a variable demand charge calculated by multiplying the applicable demand price (detailed in Table 8.11) by the CMD (expressed in kVA) minus 1,000 kVA; plus
   iii. a variable demand length charge calculated by multiplying the demand length price (detailed in Table 8.12) 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 8.11) by the CMD (expressed in kVA); plus
   ii. a variable demand length charge calculated by multiplying the demand length price (detailed in Table 8.13) 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 calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day;

d. a fixed administration charge (detailed in Table 8.17) which is payable each day; and

e. excess network usage charges calculated in accordance with section 5.5.2 (if applicable).

Notes:

1. For connection points located at the zone substation the fixed and variable demand charge specified in sections 5.5.1(a)(i), (a)(ii) & (b)(i) is to be calculated using the transmission component only. In all other instances, the fixed and variable demand charge specified in sections 5.5.1 (a)(i), (a)(ii) & (b)(i) is to be calculated using the bundled charge.
2. If this tariff applies in relation to a connection point the subject of a capacity allocation arrangement pursuant to reference services D2 as set out in Appendix E of the Access Arrangement, then the charge to each user at this connection point for the duration of the capacity allocation arrangement is the sum of all tariff components a to d, multiplied by the percentage of the contracted capacity allocated to the user pursuant to the capacity allocation arrangement as compared to the total contracted capacity at the connection point.

5.5.2 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 defined in Table 8.25;
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; and
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.
2. If the connection point is subject to the Capacity (Swap) Allocation (Business) Exit Service, for the purposes of the ENUC calculation above the CMD is the total contracted capacity allocated to the connection point from time to time pursuant to the capacity allocation arrangement.

5.6 Low voltage contract maximum demand (RT8)

5.6.1 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 8.11) which is payable each day; plus

   ii. a variable demand charge calculated by multiplying the applicable demand price (detailed in Table 8.11) by the CMD (expressed in kVA) minus 1,000 kVA; plus

   iii. a variable demand length charge calculated by multiplying the demand length price (detailed in Table 8.12) 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 8.11) by the CMD (expressed in kVA); plus

   ii. a variable demand length charge calculated by multiplying the demand length price (detailed in Table 8.13) 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 8.18) which is payable each day;

d. a variable low voltage charge calculated by multiplying the low voltage demand price (detailed in Table 8.18) by the CMD (expressed in kVA);

e. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day;

f. a fixed administration charge (detailed in Table 8.17) which is payable each day; and

g. excess network usage charges calculated in accordance with section 5.6.2 (if applicable).

Notes:

1. This tariff is identical to RT7 in section 5.5, with an additional low voltage charge to cover the use of transformers and LV circuits.
2. If this tariff applies in relation to a connection point the subject of a capacity allocation arrangement pursuant to reference services D2 as set out in Appendix E of the Access Arrangement, then the charge to each user at this connection point for the duration of the capacity allocation arrangement is the sum of all tariff components a to d, multiplied by the percentage of the contracted capacity allocated to the user pursuant to the capacity allocation arrangement as compared to the total contracted capacity at the connection point.

5.6.2 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

$ENUC_{Transmission}$	$= ENUM * (PD – CMD) * DC_{Transmission} / CMD$;
$ENUC_{Distribution}$	$= ENUM * (PD – CMD) * (DC_{Distribution} + DLC + LVC) / CMD$;
ENUM	is the Excess network usage multiplier factor, which is defined in Table 8.25;
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; and
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.
2. If the connection point is subject to the Capacity (Swap) Allocation (Business) Exit Service, for the purposes of the ENUC calculation above the CMD is the total contracted capacity allocated to the connection point from time to time pursuant to the capacity allocation arrangement.

5.7 Streetlighting (RT9)

RT9 consists of:

a. a fixed use of system charge (detailed in Table 8.1) which is payable each day;

b. a variable use of system charge calculated by multiplying the energy price (detailed in Table 8.1) 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 8.7 and Table 8.8)

5.8 Unmetered supply (RT10)

RT10 consists of:

a. a fixed use of system charge (detailed in Table 8.1) which is payable each day; and

b. a variable use of system charge calculated by multiplying the energy price (detailed in Table 8.1 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).

Except for where the consumer's facilities and equipment is a streetlight, then Reference Tariff RT10 consists of:

a. the fixed use of system charge for RT9 (detailed in Table 8.1) which is payable each day; and

b. the variable use of system charge for RT9 calculated by multiplying the energy price (detailed in Table 8.1by 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).

5.9 Distribution entry service (RT11)

5.9.1 Tariff calculation

RT11 consists of:

a. a variable connection charge calculated by multiplying the connection price (detailed in Table 8.19) 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 8.23) 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 8.21) by the loss-factor adjusted DSOC 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 8.12) 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 8.12) 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 8.13) 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 8.13) 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 calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day; and

g. excess network usage charges calculated in accordance with section 5.9.2 (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 AEMO for that generator.
2. For this reference tariff a unity power factor is assumed when converting between kW and kVA.

5.9.2 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:

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

Where

$$ENUC_{\text{Transmission}} = ENUM * (PD_{\text{kW}} - DSOC_{\text{kW}}) * TEPC / DSOC_{\text{kW}};$$

$$ENUC_{\text{Distribution}} = ENUM * (PD_{\text{kVA}} - DSOC_{\text{kVA}}) * (DLC) / DSOC_{\text{kVA}};$$

ENUM	is the Excess network usage multiplier factor, which is defined in Table 8.25;
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; and
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.

5.10 Anytime energy bi-directional (RT13 and RT14)

RT13 and RT14 consist of:

a. a fixed use of system charge (detailed in Table 8.1) which is payable each day;

b. a variable use of system charge calculated by multiplying the energy price (detailed in Table 8.1) by the quantity of electricity consumed (expressed in kWh); and

c. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day.

5.11 Time of use bi-directional (RT15 and RT16)

RT15 and RT16 consist of:

a. a fixed use of system charge (detailed in Table 8.1) 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 8.1) by the quantity of on-peak electricity consumed (expressed in kWh);

c. an off-peak use of system variable charge calculated by multiplying the off-peak energy price (detailed in Table 8.1) by the quantity of off-peak electricity consumed (expressed in kWh); and

d. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day.

Notes:

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

Table 5.4: On and off-peak for RT15 and RT16

	Monday – Friday (includes public holidays)			Saturday – Sunday (excludes public holidays)
	Off-peak	**On-Peak**	**Off-Peak**	**Off-Peak**
RT15	12:00am – 7:00am	7:00am – 9:00pm	9:00pm – 12:00am	All times
RT16	12:00am – 8:00am	8:00am – 10:00pm	10:00pm – 12:00am	All times

5.12 Three part time of use energy (RT17 and RT18)

RT17 and RT18 consist of:

a. a fixed use of system charge (detailed in Table 8.1) 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 8.1) by the quantity of on-peak electricity consumed at the connection point (expressed in kWh);

c. a shoulder use of system variable charge calculated by multiplying the shoulder energy price (detailed in Table 8.1) by the quantity of shoulder period electricity consumed at the connection point (expressed in kWh);

d. an off-peak use of system variable charge calculated by multiplying the off-peak energy price (detailed in Table 8.1) by the quantity of off-peak electricity consumed at the connection point (expressed in kWh); and

e. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day.

Notes:

1. The on-peak, shoulder and off-peak periods for these tariffs are defined in the table below (all times are WST).

Table 5.5: On and off-peak for RT17 and RT18

Monday – Friday (excludes public holidays)				Saturday – Sunday (includes public holidays)
Off-peak	**Shoulder**	**On-Peak**	**Off-Peak**	**Off-Peak**
12:00am – 12:00pm	12:00pm – 3:00pm	3:00pm – 9:00pm	9:00pm – 12:00am	All times

5.13 Three part time of use demand residential (RT19)

RT19 consist of:

a. a fixed use of system charge (detailed in Table 8.2) which is payable each day;

b. a demand based charge calculated by multiplying the demand charge (detailed in Table 8.2) by the maximum demand in a 30 minute period within the on-peak period defined below at the connection point (expressed in kW) measured over a billing period which is payable each day;

c. an on-peak use of system variable charge calculated by multiplying the on-peak energy price (detailed in Table 8.2 by the quantity of on-peak electricity consumed at the connection point (expressed in kWh);

d. a shoulder use of system variable charge calculated by multiplying the shoulder energy price (detailed in Table 8.2) by the quantity of shoulder period electricity consumed at the connection point (expressed in kWh);

e. an off-peak use of system variable charge calculated by multiplying the off-peak energy price (detailed in Table 8.2) by the quantity of off-peak electricity consumed at the connection point (expressed in kWh); and

f. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day.

Notes:

1. The on-peak, off-peak and shoulder periods for these tariffs are defined in the following table (all times are WST):

Table 5.6: On shoulder and off-peak for RT19

Monday – Friday (excludes public holidays)				Saturday – Sunday (includes public holidays)
Off-peak	**Shoulder**	**On-Peak**	**Off-Peak**	**Off-Peak**
12:00am – 12:00pm	12:00pm – 3:00pm	3:00pm – 9:00pm	9:00pm – 12:00am	All times

5.14 Three part time of use demand business (RT20)

RT20 consist of:

a. a fixed use of system charge (detailed in Table 8.2) which is payable each day;

b. a demand based charge calculated by multiplying the demand charge (detailed in Table 8.2) by the maximum demand in a 30 minute period within the on-peak period defined below at the connection point (expressed in kVA) measured over a billing period which is payable each day;

c. an on-peak use of system variable charge calculated by multiplying the on-peak energy price (detailed in Table 8.2) by the quantity of on-peak electricity consumed at the connection point (expressed in kWh);

d. a shoulder use of system variable charge calculated by multiplying the shoulder energy price (detailed in Table 8.2) by the quantity of shoulder period electricity consumed at the connection point (expressed in kWh);

e. an off-peak use of system variable charge calculated by multiplying the off-peak energy price (detailed in Table 8.2) by the quantity of off-peak electricity consumed at the connection point (expressed in kWh); and

f. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day.

Notes:

1. The on-peak, off-peak and shoulder periods for these tariffs are defined in the following table (all times are WST):

Table 5.7: On, shoulder and off-peak for RT20

Monday – Friday (excludes public holidays)				Saturday – Sunday (includes public holidays)
Off-peak	**Shoulder**	**On-Peak**	**Off-Peak**	**Off-Peak**
12:00am – 12:00pm	12:00pm – 3:00pm	3:00pm – 9:00pm	9:00pm – 12:00am	All times

5.15 Multi part time of use energy residential (RT21)

RT21 consist of:

a. a fixed use of system charge (detailed in Table 8.3) 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 8.3) by the quantity of on-peak electricity consumed at the connection point (expressed in kWh);

c. a shoulder use of system variable charge calculated by multiplying the shoulder energy price (detailed in Table 8.3) by the quantity of shoulder period electricity consumed at the connection point (expressed in kWh);

d. an off-peak use of system variable charge calculated by multiplying the off-peak energy price (detailed in Table 8.3) by the quantity of off-peak electricity consumed at the connection point (expressed in kWh);

e. an overnight use of system variable charge calculated by multiplying the overnight energy price (detailed in Table 8.3) by the quantity of overnight electricity consumed at the connection point (expressed in kWh); and

f. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day.

Notes:

1. The on-peak, off-peak, shoulder and overnight periods for this tariff are defined in the following table (all times are WST):

Table 5.8: On, shoulder, overnight and off-peak for RT21

Monday – Friday (excludes public holidays)					Saturday – Sunday (includes public holidays)	
Off-Peak	**Shoulder**	**On-Peak**	**Off-Peak**	**Overnight**	**Off-Peak**	**Overnight**
4:00am – 7:00am	7:00am – 3:00pm	3:00pm – 9:00pm	9:00pm – 11:00pm	11:00pm – 4:00am	4:00am – 11:00pm	11:00pm – 4:00am

5.16 Multi part time of use energy business (RT22)

RT22 consist of:

a. a fixed use of system charge (detailed in Table 8.3) 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 8.3) by the quantity of on-peak electricity consumed at the connection point (expressed in kWh);

c. a shoulder use of system variable charge calculated by multiplying the shoulder energy price (detailed in Table 8.3) by the quantity of shoulder period electricity consumed at the connection point (expressed in kWh);

d. an off-peak use of system variable charge calculated by multiplying the off-peak energy price (detailed in Table 8.3) by the quantity of off-peak electricity consumed at the connection point (expressed in kWh);

e. a super off-peak use of system variable charge calculated by multiplying the super off-peak energy price (detailed in Table 8.3) by the quantity of super off-peak electricity consumed at the connection point (expressed in kWh);

f. an overnight use of system variable charge calculated by multiplying the overnight energy price (detailed in Table 8.3) by the quantity of overnight electricity consumed at the connection point (expressed in kWh); and

g. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day.

Notes:

2. The on-peak, off-peak, shoulder, super off-peak and overnight periods for these tariffs are defined in the following table (all times are WST):

Table 5.9: On, shoulder, off, overnight and super off peak for RT22

Monday – Friday (excludes public holidays)					Saturday – Sunday (includes public holidays)	
Off-peak	**Shoulder**	**On-Peak**	**Off-Peak**	**Overnight**	**Off-Peak**	**Super Off-Peak**
4:00am – 7:00am	7:00am – 3:00pm	3:00pm – 9:00pm	9:00pm – 11:00pm	11:00pm – 4:00am	4:00am – 11:00pm	11:00pm – 4:00am

5.17 Super off-peak time of use energy (RT34 and RT35)

RT34 and 35 consists of:

a. a fixed use of system charge (detailed in Table 8.3) 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 8.3) by the quantity of on-peak electricity consumed at the connection point (expressed in kWh);

c. a shoulder use of system variable charge calculated by multiplying the shoulder energy price (detailed in Table 8.3) by the quantity of shoulder period electricity consumed at the connection point (expressed in kWh);

d. an off-peak use of system variable charge calculated by multiplying the off-peak energy price (detailed in Table 8.3) by the quantity of off-peak electricity consumed at the connection point (expressed in kWh);

e. a super off-peak use of system variable charge calculated by multiplying the super off-peak energy price (detailed in Table 8.3) by the quantity of super off-peak electricity consumed at the connection point (expressed in kWh); and

f. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day.

Notes:

1. The on-peak, off-peak, shoulder, and super off-peak periods for these tariffs are defined in the following table (all times are WST):

Table 5.10: On, shoulder, off and super off peak for RT34 and RT35

Every day (Monday – Sunday (including public holidays))					
Off-Peak	**Shoulder**	**Super off-peak**	**On-Peak**	**Shoulder**	**Off-peak**
12:00am – 6:00am	6:00am – 9:00am	9:00am – 3:00pm	3:00pm – 9:00pm	9:00pm – 11:00pm	11:00pm – 12:00am

5.18 Super off-peak time of use demand business (RT36)

RT36 consists of:

a. a fixed use of system charge (detailed in Table 8.3) which is payable each day;

b. a demand based charge calculated by multiplying the demand charge (detailed in Table 8.3) by the maximum demand in a 30 minute period within the on-peak period defined below at the connection point (expressed in kVA) measured over a billing period which is payable each day;
c. an on-peak use of system variable charge calculated by multiplying the on-peak energy price (detailed in Table 8.3) by the quantity of on-peak electricity consumed at the connection point (expressed in kWh);
d. a shoulder use of system variable charge calculated by multiplying the shoulder energy price (detailed in Table 8.3) by the quantity of shoulder period electricity consumed at the connection point (expressed in kWh);
e. an off-peak use of system variable charge calculated by multiplying the off-peak energy price (detailed in Table 8.3) by the quantity of off-peak electricity consumed at the connection point (expressed in kWh);
f. a super off-peak use of system variable charge calculated by multiplying the super off-peak energy price (detailed in Table 8.3) by the quantity of super off-peak electricity consumed at the connection point (expressed in kWh); and
g. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14and Table 8.15) which is payable each day.

Notes:

1. The on-peak, off-peak, shoulder, and super off-peak periods for these tariffs are defined in the following table (all times are WST):

Table 5.11: On, shoulder, off and super off peak for RT36

Every day (Monday – Sunday (including public holidays))					
Off-Peak	**Shoulder**	**Super off-peak**	**On-Peak**	**Shoulder**	**Off-peak**
12:00am – 6:00am	6:00am – 9:00am	9:00am – 3:00pm	3:00pm – 9:00pm	9:00pm – 11:00pm	11:00pm – 12:00am

5.19 Super off-peak time of use demand residential (RT37)

RT37 consists of:

a. a fixed use of system charge (detailed in Table 8.3) which is payable each day;
b. a demand based charge calculated by multiplying the demand charge (detailed in Table 8.3 by the maximum demand in a 30 minute period within the on-peak period defined below at the connection point (expressed in kW) measured over a billing period which is payable each day;
c. an on-peak use of system variable charge calculated by multiplying the on-peak energy price (detailed in Table 8.3) by the quantity of on-peak electricity consumed at the connection point (expressed in kWh);
d. a shoulder use of system variable charge calculated by multiplying the shoulder energy price (detailed in Table 8.3) by the quantity of shoulder period electricity consumed at the connection point (expressed in kWh);

e. an off-peak use of system variable charge calculated by multiplying the off-peak energy price (detailed in Table 8.3) by the quantity of off-peak electricity consumed at the connection point (expressed in kWh);

f. a super off-peak use of system variable charge calculated by multiplying the super off-peak energy price (detailed in Table 8.3) by the quantity of super off-peak electricity consumed at the connection point (expressed in kWh); and

g. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day.

Notes:

1. The on-peak, off-peak, shoulder, and super off-peak periods for these tariffs are defined in the following table (all times are WST):

Table 5.12: On, shoulder, off and super off peak for RT37

Every day (Monday – Sunday (including public holidays))					
Off-Peak	**Shoulder**	**Super off-peak**	**On-Peak**	**Shoulder**	**Off-peak**
12:00am – 6:00am	6:00am – 9:00am	9:00am – 3:00pm	3:00pm – 9:00pm	9:00pm – 11:00pm	11:00pm – 12:00am

6. Transmission tariffs

6.1 Transmission exit service (TRT1)

6.1.1 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, subject to the limit as set out in Appendix B.1.1;

b. a variable use of system charge calculated by multiplying the applicable use of system price (detailed in Table 8.20) or where there is no applicable use of system price in Table 8.20 for the exit point, the price calculated by Western Power in accordance with Appendix B of this Price List 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 8.22) 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 8.24) by the CMD at the exit point (expressed in kW);

e. a fixed metering charge per revenue meter (detailed in Table 8.14) which is payable each day; and

f. excess network usage charges calculated in accordance with section 6.1.2 (if applicable).

6.1.2 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 defined in Table 8.25;
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.
2. If the connection point is subject to the Capacity (Swap) Allocation Service, for the purposes of the ENUC calculation above the CMD is the total contracted capacity allocated to the connection point from time to time pursuant to the capacity allocation arrangement.

6.2 Transmission entry service (TRT2)

6.2.1 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, subject to the limit as set out in Appendix B.1.1;

b. a variable use of system charge calculated by multiplying the applicable use of system price (detailed in Table 8.21) or where there is no applicable use of system price in Table 8.21 for the entry point, the price calculated by Western Power in accordance with Appendix B of this Price List 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 8.23 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 8.14) which is payable each day; and

e. excess network usage charges calculated in accordance with section 6.2.2 (if applicable).

6.2.2 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 defined in Table 8.25;
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; and
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.

6.3 Transmission storage service (TRT3)

TRT3 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, subject to the limit as set out in Appendix B.1.1;

b. a variable use of system charge calculated by multiplying the applicable use of system price (detailed in Table 8.21) or where there is no applicable use of system price in Table 8.21 for the entry point, the price calculated by Western Power in accordance with Appendix B of this Price List 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 8.23 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 8.14) which is payable each day; and

e. excess network usage charges calculated in accordance with section 6.2.2 (if applicable).

6.3.1 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 defined in Table 8.25;
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; and
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.

7. Other tariffs

7.1 Entry Service Facilitating a Distributed Generation or Other Non-Network Solution (RT23)

7.1.1 Tariff calculation

RT23 consists of:

a. the reference tariff (RT11) applicable to the entry reference service B1 upon which the B3 – Entry Service Facilitating a Distributed Generation or Other Non-Network Solution is provided; less

b. the discount that applies to the connection point as set out in clause 7.1.2 below.

7.1.2 Discount

Western Power will provide a discount to RT11 in circumstances where the service allows for facilities and equipment connected behind the connection point (including distributed generating plant and other non-network solutions) that results in Western Power's capital-related costs or non-capital costs reducing as a result of the entry point for the distributed generating plant or other non-network solution being located in that particular part of the covered network.

In situations where a user connects facilities and equipment (including distributed generating plant) to the Western Power Network and has applied and been assessed as resulting in Western Power's capital-related costs or non-capital costs reducing as a result of the entry point for the distributed generating plant or other non-network solution being located in that particular part of the covered network, the discount to be applied is an annualised discount amount (which can be no greater than the annual charge), calculated as the present value of FCp less FCn over a period of Y years using discount rate W.

Where:

FCp	is the present value of the Western Power committed forecast capital-related costs and non-capital costs that would be incurred over Y years if the facilities and equipment (including distributed generating plant) were not to connect to the Western Power Network.
FCn	is the present value of Western Power's forecast capital-related costs and non-capital costs over Y years that are anticipated to be incurred if the facilities and equipment (including distributed generating plant) were to connect to the Western Power Network.
Y	is the period over which the present value assessment is to occur which is 15 years unless otherwise agreed between Western Power and the user.
W	is the Weighted Average Cost of Capital as set out in section 5.4 of the Access Arrangement that applies in the pricing year.

7.2 Bi-directional Service Facilitating a Distributed Generation or Other Non-Network Solution (RT24)

7.2.1 Tariff calculation

RT24 consists of:

a. the reference tariff (RT5 - RT8, RT13 - RT22 and RT34 - 37) applicable to the bi-directional reference service identified from C1 to C14 and C16 to C19 upon which the C15 - Bi-directional Service Facilitating a Distributed Generation or Other Non-Network Solution is provided; less

b. the discount that applies to the connection point as set out in clause 7.2.2 below.

7.2.2 Discount

Western Power will provide a discount to (RT5 - RT8, RT13 - RT22 and RT34 - 37) in circumstances where the service allows for facilities and equipment connected behind the connection point (including distributed generating plant and other non-network solutions) that results in Western Power's capital-related costs or non-capital costs reducing as a result of the entry point for the distributed generating plant or other non-network solution being located in that particular part of the covered network.

In situations where a user connects facilities and equipment (including distributed generating plant) to the Western Power Network and has applied and been assessed as resulting in Western Power's capital-related costs or non-capital costs reducing as a result of the entry point for the distributed generating plant or other non-network solution being located in that particular part of the covered network, the discount to be applied is an annualised discount amount (which can be no greater than the annual charge), calculated as the present value of FCp less FCn over a period of Y years using discount rate W.

Where:

FCp	is the present value of the Western Power forecast capital-related costs and non-capital costs that would be incurred over Y years if the facilities and equipment (including distributed generating plant) were not to connect to the Western Power Network.
FCn	is the present value of Western Power's forecast capital-related costs and non-capital costs over Y years that are anticipated to be incurred if the facilities and equipment (including distributed generating plant) were to connect to the Western Power Network.
Y	is the period over which the present value assessment is to occur which is 15 years unless otherwise agreed between Western Power and the user.
W	is the Weighted Average Cost of Capital as set out in section 5.4 of the Access Arrangement that applies in the pricing year.

7.3 Supply abolishment service (RT25)

7.3.1 Tariff calculation

RT25 consists of a charge per connection point supply abolishment (detailed in Table 8.26).

7.4 Remote load/inverter control service (RT26)

7.4.1 Tariff calculation

RT26 consists of a charge per request to remotely control load (detailed in Table 9.1).

7.5 Remote de-energise service (RT28)

7.5.1 Tariff calculation

RT28 consists of a charge per request for de-energisation (detailed in Table 8.27).

7.6 Remote de-energise service (RT29)

7.6.1 Tariff calculation

RT29 consists of a charge per request for re-energisation (detailed in Table 8.27).

7.7 LED replacement service (RT30)

7.7.1 Tariff calculation

RT30 consists of a user-specific charge that is to be an amount which reflects the costs to Western Power of replacing the existing streetlight with the LED streetlight replacement requested by the user which may consist of capital and non-capital costs.

7.8 Site Visit to Support Remote Re-energise Service (RT31)

RT31 consists of a charge per request for a site visit to support remote re-energisation of a site (detailed in Table 8.28).

7.9 Manual De-energise Service (RT32)

RT32 consists of a charge per request for manual de-energisation of a site (detailed in Table 8.28).

7.10 Manual Re-energise Service (RT33)

RT33 consists of a charge per request for manual re-energisation of a site (detailed in Table 8.28).

7.11 Distribution storage service (RT38 and RT39)

7.11.1 Tariff calculation

RT38 and RT39 consists of:

a. a fixed use of system charge that reflects the costs of providing connection assets (detailed in Table 8.5) which is payable each day;

b. for nett consumption from the Western Power network:

   i. an on-peak use of system variable charge calculated by multiplying the on-peak energy price (detailed in Table 8.4) by the quantity of on-peak electricity consumed at the connection point (expressed in kWh);

   ii. a shoulder use of system variable charge calculated by multiplying the shoulder energy price (detailed in Table 8.4) by the quantity of shoulder period electricity consumed at the connection point (expressed in kWh);

iii. an off-peak use of system variable charge calculated by multiplying the off-peak energy price (detailed in Table 8.4) by the quantity of off-peak electricity consumed at the connection point (expressed in kWh);

iv. a super off-peak use of system variable charge calculated by multiplying the super off-peak energy price (detailed in Table 8.4) by the quantity of super off-peak electricity consumed at the connection point (expressed in kWh);

c. for nett exports to the Western Power network:

i. an on-peak use of system variable charge calculated by multiplying the on-peak energy price (detailed in Table 8.4) by the quantity of on-peak electricity exported at the connection point (expressed in kWh);

ii. a shoulder use of system variable charge calculated by multiplying the shoulder energy price (detailed in Table 8.4) by the quantity of shoulder period electricity exported at the connection point (expressed in kWh);

iii. an off-peak use of system variable charge calculated by multiplying the off-peak energy price (detailed in Table 8.4) by the quantity of off-peak electricity exported at the connection point (expressed in kWh);

iv. a stepped super off-peak use of system variable charge calculated by multiplying:

A. the first 3kWh of super off-peak electricity exported (expressed in kWh) at the connection point by the super off-peak energy price (detailed in Table 8.4) measured over a billing period which is payable each day; and

B. the quantity of super off-peak electricity in excess of 3kWh exported (expressed in kWh) at the connection point by the super off-peak energy price (detailed in Table 8.4) measured over a billing period which is payable each day.

d. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day.

Notes:

1. The on-peak, off-peak, shoulder, and super off-peak periods for these tariffs are defined in the following table (all times are WST):

Table 7.1: On, shoulder, off and super off peak for RT38 and RT39

Every day (Monday – Sunday (including public holidays))					
Off-Peak	**Shoulder**	**Super off-peak**	**On-Peak**	**Shoulder**	**Off-peak**
12:00am – 6:00am	6:00am – 9:00am	9:00am – 3:00pm	3:00pm – 9:00pm	9:00pm – 11:00pm	11:00pm – 12:00am

7.12 EV charging service (RT40 and RT41)

7.12.1 Tariff calculation

RT40 and RT41 consists of:

a. a fixed use of system charge that reflects the costs of providing connection assets (detailed in Table 8.6) which is payable each day;

b. an on-peak use of system variable charge that varies with network utilisation defined below which is calculated by multiplying the on-peak energy price relevant to the network utilisation percentage band (detailed in Table 8.6) by the quantity of on-peak electricity consumed at the connection point (expressed in kWh);

c. a shoulder use of system variable charge that varies with network utilisation defined below which is calculated by multiplying the shoulder energy price relevant to the network utilisation percentage band (detailed in Table 8.6) by the quantity of shoulder electricity consumed at the connection point (expressed in kWh);

d. an off-peak use of system variable charge that varies with network utilisation defined below which is calculated by multiplying the off-peak energy price relevant to the network utilisation percentage band (detailed in Table 8.6) by the quantity of off-peak electricity consumed at the connection point (expressed in kWh);

e. a super off-peak use of system variable charge that varies with network utilisation defined below which is calculated by multiplying the super off-peak energy price relevant to the network utilisation percentage band (detailed in Table 8.6) by the quantity of super off-peak electricity consumed at the connection point (expressed in kWh);

f. a demand-based charge that varies with network utilisation defined below calculated by multiplying the demand charge relevant to the network utilisation percentage band (detailed in Table 8.6) by the maximum demand in a 30-minute period within the on-peak period defined below at the connection point (expressed in kVA) measured over a billing period which is payable each day;

g. a fixed metering charge per revenue meter calculated in accordance with section 8.2.3 (detailed in Table 8.14 and Table 8.15) which is payable each day.

Notes:

1. The on-peak, shoulder, super off-peak and off-peak periods for these tariffs are defined in the following table (all times are WST):

Table 7.2: On, shoulder, off and super off peak for RT40 and RT41

Every day (Monday – Sunday (including public holidays))					
Off-peak	**Shoulder**	**Super off-peak**	**On-peak**	**Shoulder**	**Off-peak**
12:00am – 6:00am	6:00am – 9:00am	9:00am – 3:00pm	3:00pm – 9:00pm	9:00pm – 11:00pm	11:00pm – 12:00am

7.12.2 Calculation of network utilisation

Western Power has designed a measure of network utilisation to provide strong support to EV charging stations during this access arrangement. The calculation of network utilisation:

- Is based on demand in the twelve 30-minute intervals between 3pm and 9pm (being the on-peak period); and
- excludes any 30-minute interval where demand is less than 10kW.

The formula for calculation of the network utilisation for this tariff is:

$$\frac{30\ minute\ intervals\ with\ demand\ above\ 10kW\ between\ 3pm\ and\ 9pm}{30\ minute\ intervals\ in\ a\ billing\ period}$$

The resultant percentage from the above calculation is used to assign the site to the relevant network utilisation percentage band as set out below that will set out the network charges applicable to the site.

7.12.3 Defining the network utilisation percentage bands

For the purposes of this tariff, Western Power has defined three network utilisation percentage bands that set out the applicable use of system variable charges and demand-based charge that will apply to the connection point as defined in the following table:

Table 7.3: Network utilisation bands

Network utilisation percentage bands	
1	≥ 0% and < 15%
2	≥ 15% and < 30%
3	≥ 30%

8. Price tables

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

Table 8.11, Table 8.20 and Table 8.21 include a Transmission Node Identity (TNI) to uniquely identify zone substations.

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

8.1 Prices for energy-based tariffs on the distribution network

8.1.1 Use of system prices

The prices in the following tables are applicable for reference tariffs **RT1, RT2, RT3, RT4, RT9, RT10, RT13, RT14, RT15, RT16, RT 17, RT18, RT19, RT20, RT21, RT22, RT34, RT35, RT36, RT37, RT38, RT39, RT40 and RT41**.

Table 8.1: Reference tariffs prices for RT1, RT2, RT3, RT4, RT9, RT10, RT13, RT14, RT15, RT16, RT17 and RT18

Bundled tariff	Fixed Price c/day	Energy Rates			
		Anytime c/kWh	On-Peak c/kWh	Shoulder c/kWh	Off-Peak c/kWh
Reference tariff 1 - RT1	96.519	8.673	-	-	-
Reference tariff 2 - RT2	182.049	11.831	-	-	-
Reference tariff 3 - RT3	96.519	-	18.269	-	3.945
Reference tariff 4 - RT4	333.276	-	19.539	-	4.520
Reference tariff 9 – RT9	7.706	5.197	-	-	-
Reference tariff 10 – RT10	60.033	4.848	-	-	-
Reference tariff 13 - RT13	96.519	8.673	-	-	-
Reference tariff 14 - RT14	182.049	11.831	-	-	-
Reference tariff 15 - RT15	96.519	-	18.269	-	4.014
Reference tariff 16 - RT16	333.276	-	19.539	-	4.520
Reference tariff 17 - RT17	96.519	-	12.475	8.496	6.120
Reference tariff 18 - RT18	182.049	-	18.956	13.534	9.595

Table 8.2: Reference tariffs for RT19 and RT20

Bundled tariff	Fixed Price c/day	Demand c/kW or kVA/day	Energy Rates		
			On-Peak c/kWh	Shoulder c/kWh	Off-Peak c/kWh
Reference tariff 19 – RT19	96.519	6.095	10.781	7.489	5.078
Reference tariff 20 - RT20	228.536	7.277	17.915	11.740	8.511

Table 8.3: Reference tariffs for RT21, RT22, RT34, RT35, RT36 and RT37

Bundled tariff	Fixed Price	Demand	Energy Rates				
	c/day	c/kW or KVA/day	On-Peak c/kWh	Shoulder c/kWh	Off-Peak c/kWh	Overnight c/kWh	Super Off-Peak c/kWh
Reference tariff 21 – RT21	96.519	-	12.429	8.307	5.867	5.867	-
Reference tariff 22 – RT22	182.049	-	19.603	12.546	8.745	8.745	8.745
Reference tariff 34 – RT34	182.049	-	19.050	9.520	7.330	-	5.000
Reference tariff 35 – RT35	96.519	-	15.295	7.647	5.883	-	0.100
Reference tariff 36 – RT36	333.276	6.804	17.220	8.610	6.620	-	5.000
Reference tariff 37 – RT37	96.519	5.699	11.348	5.674	4.365	-	0.100

Table 8.4: Reference tariffs for RT38 and RT39

<table>
<tr><th rowspan="2">Bundled tariff</th><th>Fixed Price</th><th colspan="5">Energy Rates (network to storage - charging)</th></tr>
<tr><th>c/day</th><th>Off-Peak c/kWh</th><th>Shoulder c/kWh</th><th colspan="2">Super Off-Peak c/kWh</th><th>On-Peak c/kWh</th></tr>
<tr><td rowspan="4">Reference tariff 38 – RT38</td><td rowspan="4">Varies with capacity see Table D.5 below</td><td>0.100</td><td>9.520</td><td colspan="2">0.100</td><td>19.050</td></tr>
<tr><th colspan="5">Energy Rates (storage to network – discharging)</th></tr>
<tr><th>Off-Peak c/kWh</th><th>Shoulder c/kWh</th><th>Super Off-peak 0-3 kWh c/kWh</th><th>Super Off-Peak > 3 kWh c/kWh</th><th>On-Peak c/kWh</th></tr>
<tr><td>0.100</td><td>0.100</td><td>9.520</td><td>19.050</td><td>0.100</td></tr>
<tr><th rowspan="2">Bundled tariff</th><th>Fixed Price</th><th colspan="5">Energy Rates (network to storage - charging)</th></tr>
<tr><th>c/day</th><th>Off-Peak c/kWh</th><th>Shoulder c/kWh</th><th colspan="2">Super Off-Peak c/kWh</th><th>On-Peak c/kWh</th></tr>
<tr><td rowspan="2">Reference tariff 39 – RT39</td><td rowspan="2">Varies with capacity see</td><td>0.100</td><td>9.520</td><td colspan="2">0.100</td><td>19.050</td></tr>
<tr><th colspan="5">Energy Rates (storage to network - discharging)</th></tr>
</table>

	Table D.5 below	Off-Peak c/kWh	Shoulder c/kWh	Super Off-peak 0-3 kWh c/kWh	Super Off-Peak > 3 kWh c/kWh	On-Peak c/kWh
		0.100	0.100	9.520	19.050	0.100

Table 8.5: Fixed Price for Reference tariffs for RT38 and RT39

Capacity of storage works kVA	Fixed Price c/day
≥ 0 and < 100	350.000
≥100 and < 1,000	700.000
≥1,000 and < 3,000	1,500.000
≥ 3,000	1,500.000

Table 8.6: Reference tariffs for RT40 and RT41

Bundled tariff	Utilisation %	Fixed Price c/day	Energy Rates				
			Off-Peak c/kWh	Shoulder c/kWh	On-Peak c/kWh	Super Off-peak c/kWh	Demand On-peak c/kVA/day
Reference tariff 40 – RT40	≥0 & <15	350.000	6.154	8.000	16.000	6.000	0.000
	≥15 & <30	350.000	3.077	4.000	8.000	3.000	15.000
	≥30	350.000	1.538	2.000	4.000	1.500	30.000
Reference tariff 41 – RT41	≥0 & <15	350.000	6.154	8.000	16.000	6.000	0.000
	≥15 & <30	350.000	3.077	4.000	8.000	3.000	15.000
	≥30	350.000	1.538	2.000	4.000	1.500	30.000

8.1.2 Streetlight asset prices

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

Table 8.7: Current light types

Light specification	Daily charge (No contribution) c/day[4]	Daily charge (Full upfront contribution) c/day[5]
42 CFL DECORATIVE	43.160	N/A
42 CFL STANDARD	43.160	N/A
150 HPS STANDARD	48.443	N/A
20 LED DECORATIVE	48.672	16.771
53 LED DECORATIVE	48.672	16.771
80 LED DECORATIVE	48.672	16.771
100 LED DECORATIVE	54.670	16.771
170 LED DECORATIVE	54.670	16.771
16 LED STANDARD	22.766	16.771
18 LED STANDARD	22.766	16.771
20 LED STANDARD	22.766	16.771
28 LED STANDARD	22.766	16.771
36 LED STANDARD	22.766	16.771
42 LED STANDARD	22.950	16.771
43 LED STANDARD	22.950	16.771
53 LED STANDARD	22.950	16.771
70 LED STANDARD	22.729	16.771
80 LED STANDARD	22.729	16.771
135 LED STANDARD	24.936	16.771
140 LED STANDARD	24.936	16.771
165 LED STANDARD	24.936	16.771
170 LED STANDARD	24.936	16.771
16 LED DECORATIVE	48.672	16.771
14 LED DECORATIVE	48.672	16.771
150 LED DECORATIVE	54.670	16.771

[4] As a result of an increase in the regulated streetlighting asset base and changes to the weighted average cost of capital between AA4 and AA5, in addition to asset prices being held constant over the 2022-23 pricing year, there has been an uplift in the daily asset charge for the 2023-24 pricing year. Future pricing years over AA5 show more modest increases in the daily asset charge.

[5] For the purposes of RT9, users may access the “fully funded” tariff rate where a user and/or customer has applied for the LED replacement ancillary service D10 under Appendix E of Western Power’s approved access arrangement and paid the amount required with regard to reference tariff RT30.

Light specification	Daily charge (No contribution) c/day[4]	Daily charge (Full upfront contribution) c/day[5]
30 LED DECORATIVE	48.672	16.771

Table 8.8: Obsolete light types

Light specification	Daily charge c/day
70 HPS STANDARD	36.826
17 LED DECORATIVE	46.354
34 LED DECORATIVE	46.354
36 LED DECORATIVE	46.354
42 LED DECORATIVE	42.378
155 LED DECORATIVE	54.670
27 LED STANDARD	22.766
68 LED STANDARD	22.729
155 LED STANDARD	24.936
160 LED STANDARD	24.936
70 MH STANDARD	74.877
150 MH STANDARD	86.507
40 FLU STANDARD	27.414
80 HPS STANDARD	37.900
125 HPS STANDARD	49.856
250 HPS STANDARD	48.443
100 INC STANDARD	27.414
22 LED STANDARD	22.766
80 MH STANDARD	36.898
125 MH STANDARD	89.033
250 MH STANDARD	86.507
50 MV STANDARD	27.414
70 MV STANDARD	36.898
80 MV STANDARD	36.898
150 MV STANDARD	45.874
250 MV STANDARD	59.841
400 MV STANDARD	62.831

Light specification	Daily charge c/day
125W MV STANDARD	45.874

8.2 Prices for demand-based tariffs on the distribution network (RT5 to RT8 and RT11[6])

8.2.1 Demand charges

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

Table 8.9: Prices for reference tariff RT5

Demand (kVA) (Lower to upper threshold)	Bundled tariff	
	Fixed c/day	Demand (in excess of lower threshold) c/kVA/day
0 to 300	191.935	89.367
300 to 1,000	26,810.100	64.919
1,000 to 1,500	72,253.400	31.109

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

Table 8.10: Prices for reference tariff RT6

Demand (kVA) (Lower to upper threshold)	Bundled tariff	
	Fixed c/day	Demand (in excess of lower threshold) c/kVA/day
0 to 300	1,107.610	93.102
300 to 1,000	27,930.600	71.731
1,000 to 1,500	78,142.300	37.416

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

[6] Note that some components of RT11 are in section 8.3.

Table 8.11: Prices for reference tariffs RT7 and RT8

Zone substation	TNI	Pricing zone	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)
Cook Street	WCKT	CBD	55,438.139	30.861	34.372
Forrest Avenue	WFRT	CBD	55,438.139	30.861	34.372
Hay Street	WHAY	CBD	55,438.139	30.861	34.372
Milligan Street	WMIL	CBD	55,438.139	30.861	34.372
Wellington Street	WWNT	CBD	55,438.139	30.861	34.372
Black Flag	WBKF	Mining	55,438.139	45.987	47.337
Boulder	WBLD	Mining	55,438.139	42.854	44.652
Bounty	WBNY	Mining	55,438.139	76.829	73.773
West Kalgoorlie	WWKT	Mining	55,438.139	38.833	41.205
Albany	WALB	Mixed	55,438.139	51.261	51.858
Boddington	WBOD	Mixed	55,438.139	31.169	34.636
Bunbury Harbour	WBUH	Mixed	55,438.139	30.749	34.276
Busselton	WBSN	Mixed	55,438.139	39.187	41.509
Byford	WBYF	Mixed	55,438.139	32.149	35.476
Capel	WCAP	Mixed	55,438.139	36.165	38.918
Chapman	WCPN	Mixed	55,438.139	44.230	45.831
Darlington	WDTN	Mixed	55,438.139	34.506	37.496
Durlacher Street	WDUR	Mixed	55,438.139	41.104	43.152
Eneabba	WENB	Mixed	55,438.139	39.351	41.649
Geraldton	WGTN	Mixed	55,438.139	41.104	43.152
Marriott Road	WMRR	Mixed	55,438.139	30.107	33.726
Muchea	WMUC	Mixed	55,438.139	34.322	37.339
Northam	WNOR	Mixed	55,438.139	42.129	44.030
Picton	WPIC	Mixed	55,438.139	32.247	35.560
Rangeway	WRAN	Mixed	55,438.139	43.020	44.794
Sawyers Valley	WSVY	Mixed	55,438.139	39.590	41.854
Yanchep	WYCP	Mixed	55,438.139	34.245	37.273

Zone substation	TNI	Pricing zone	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)
Yilgarn	WYLN	Mixed	55,438.139	48.672	49.639
Baandee	WBDE	Rural	55,438.139	45.737	47.123
Beenup	WBNP	Rural	55,438.139	48.846	49.788
Bridgetown	WBTN	Rural	55,438.139	31.514	34.932
Carrabin	WCAR	Rural	55,438.139	49.804	50.609
Cataby	WKMC	Rural	55,438.139	32.442	35.727
Collie	WCOE	Rural	55,438.139	36.453	39.165
Coolup	WCLP	Rural	55,438.139	40.509	42.642
Cunderdin	WCUN	Rural	55,438.139	42.458	44.312
Katanning	WKAT	Rural	55,438.139	39.131	41.461
Kellerberrin	WKEL	Rural	55,438.139	44.653	46.194
Kojonup	WKOJ	Rural	55,438.139	28.505	32.353
Kondinin	WKDN	Rural	55,438.139	30.359	33.942
Manjimup	WMJP	Rural	55,438.139	31.297	34.746
Margaret River	WMRV	Rural	55,438.139	39.255	41.567
Merredin	WMER	Rural	55,438.139	40.914	42.989
Moora	WMOR	Rural	55,438.139	31.581	34.989
Mount Barker	WMBR	Rural	55,438.139	40.807	42.897
Narrogin	WNGN	Rural	55,438.139	45.471	46.895
Pinjarra	WPNJ	Rural	55,438.139	23.751	28.278
Regans	WRGN	Rural	55,438.139	32.442	35.727
Three Springs	WTSG	Rural	55,438.139	31.499	34.919
Wagerup	WWGP	Rural	55,438.139	22.841	27.498
Wagin	WWAG	Rural	55,438.139	39.618	41.878
Wundowie	WWUN	Rural	55,438.139	35.166	38.062
Yerbillon	WYER	Rural	55,438.139	48.637	49.609
Amherst	WAMT	Urban	55,438.139	22.894	27.543
Arkana	WARK	Urban	55,438.139	22.894	27.543

Zone substation	TNI	Pricing zone	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)
Australian Paper Mills	WAPM	Urban	55,438.139	22.894	27.543
Balcatta	WBCT	Urban	55,438.139	22.894	27.543
Beechboro	WBCH	Urban	55,438.139	22.894	27.543
Belmont	WBEL	Urban	55,438.139	22.894	27.543
Bentley	WBTY	Urban	55,438.139	22.894	27.543
Bibra Lake	WBIB	Urban	55,438.139	22.894	27.543
British Petroleum	WBPM	Urban	55,438.139	22.894	27.543
Canning Vale	WCVE	Urban	55,438.139	22.894	27.543
Clarence Street	WCLN	Urban	55,438.139	22.894	27.543
Clarkson	WCKN	Urban	55,438.139	22.894	27.543
Cockburn Cement	WCCT	Urban	55,438.139	22.894	27.543
Collier	WCOL	Urban	55,438.139	22.894	27.543
Cottesloe	WCTE	Urban	55,438.139	22.894	27.543
Edmund Street	WEDD	Urban	55,438.139	22.894	27.543
Forrestfield	WFFD	Urban	55,438.139	22.894	27.543
Gosnells	WGNL	Urban	55,438.139	22.894	27.543
Hadfields	WHFS	Urban	55,438.139	22.894	27.543
Hazelmere	WHZM	Urban	55,438.139	22.894	27.543
Henley Brook	WHBK	Urban	55,438.139	22.894	27.543
Herdsman Parade	WHEP	Urban	55,438.139	22.894	27.543
Joel Terrace	WJTE	Urban	55,438.139	22.894	27.543
Joondalup	WJDP	Urban	55,438.139	22.894	27.543
Kalamunda	WKDA	Urban	55,438.139	22.894	27.543
Kambalda	WKBA	Urban	55,438.139	39.187	41.509
Kewdale	WKDL	Urban	55,438.139	22.894	27.543
Landsdale	WLDE	Urban	55,438.139	22.894	27.543
Maddington	WMDN	Urban	55,438.139	22.894	27.543
Malaga	WMLG	Urban	55,438.139	22.894	27.543

Zone substation	TNI	Pricing zone	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)
Mandurah	WMHA	Urban	55,438.139	22.894	27.543
Manning Street	WMAG	Urban	55,438.139	22.894	27.543
Mason Road	WMSR	Urban	55,438.139	22.894	27.543
Meadow Springs	WMSS	Urban	55,438.139	22.894	27.543
Medical Centre	WMCR	Urban	55,438.139	22.894	27.543
Medina	WMED	Urban	55,438.139	22.894	27.543
Midland Junction	WMJX	Urban	55,438.139	22.894	27.543
Morley	WMOY	Urban	55,438.139	22.894	27.543
Mullaloo	WMUL	Urban	55,438.139	22.894	27.543
Mundaring Weir	WMWR	Urban	55,438.139	22.894	27.543
Munday	WMDY	Urban	55,438.139	22.894	27.543
Murdoch	WMUR	Urban	55,438.139	22.894	27.543
Myaree	WMYR	Urban	55,438.139	22.894	27.543
Nedlands	WNED	Urban	55,438.139	22.894	27.543
North Beach	WNBH	Urban	55,438.139	22.894	27.543
North Fremantle	WNFL	Urban	55,438.139	22.894	27.543
North Perth	WNPH	Urban	55,438.139	22.894	27.543
O'Connor	WOCN	Urban	55,438.139	22.894	27.543
Osborne Park	WOPK	Urban	55,438.139	22.894	27.543
Padbury	WPBY	Urban	55,438.139	22.894	27.543
Piccadilly	WPCY	Urban	55,438.139	36.991	39.626
Riverton	WRTN	Urban	55,438.139	22.894	27.543
Rivervale	WRVE	Urban	55,438.139	22.894	27.543
Rockingham	WROH	Urban	55,438.139	22.894	27.543
Shenton Park (Old)	WSPA	Urban	55,438.139	22.894	27.543
Shenton Park (New AA5)	WSPK	Urban	55,438.139	22.894	27.543
Sth Ftle Power Station	WSFT	Urban	55,438.139	22.894	27.543
Southern River	WSNR	Urban	55,438.139	22.894	27.543

Zone substation	TNI	Pricing zone	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)
Southern Cross	WSNX	Mixed	55,438.139	48.672	49.639
Tate Street	WTTS	Urban	55,438.139	22.894	27.543
University	WUNI	Urban	55,438.139	22.894	27.543
Victoria Park	WVPA	Urban	55,438.139	22.894	27.543
Waikiki	WWAI	Urban	55,438.139	22.894	27.543
Wangara	WWGA	Urban	55,438.139	22.894	27.543
Wanneroo	WWNO	Urban	55,438.139	22.894	27.543
Welshpool	WWEL	Urban	55,438.139	22.894	27.543
Wembley Downs	WWDN	Urban	55,438.139	22.894	27.543
Willetton	WWLN	Urban	55,438.139	22.894	27.543
Yokine	WYKE	Urban	55,438.139	22.894	27.543

8.2.2 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 8.12: Reference for tariffs RT5, RT6, RT7, RT8 and RT11

Pricing zone	Demand-Length Charge	
	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	1.765	1.247
Mining	0.378	0.264
Mixed	0.823	0.569
Rural	0.512	0.357

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

Table 8.13: Reference tariffs RT7, RT8 and RT11

Pricing zone	Demand-Length Charge	
	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	1.511	1.247
Mining	0.326	0.228
Mixed	0.709	0.492
Rural	0.445	0.305

8.2.3 Metering prices

The prices in the following table are applicable for all reference tariffs (excluding RT9, RT10, RT25, RT26, and RT28 to RT33).

The total metering price payable is the sum of the applicable charge in Table 8.14, which is based on the reference tariff of the connection point and the charge in Table 8.15, which is based on the metering reference service applicable to the connection point, or as selected by the retailer. The applicable metering reference service for each reference service is defined in Appendix E, table E.1.2[7].

Note that for billing purposes, Western Power will calculate the total metering charge per connection point (a sum of the relevant charge in Table 8.14 and Table 8.15) as a single daily charge.

For the purposes of the Metering Model Service Level Agreement, the charges in Table 8.15 (M1 – M15 and M17 – M20) are considered to be the incremental fees involved in providing the additional metering services.

Table 8.14: Metering prices[8]

Reference Tariff	c/revenue meter/day
RT1	8.154
RT2	8.606
RT3	8.478
RT4	13.373
RT5 – RT8	14.743
RT11	14.743
RT13	8.154
RT14	8.606
RT15	8.158

7 https://www.erawa.com.au/cproot/20419/2/ERA-Approved---Appendix-E---Reference-Services.pdf

8 Additional charges will apply if the user has selected a non-standard metering service for the relevant exit, entry or bi-directional service. The charge will reflect Western Power's incremental costs of providing the additional metering services and may consist of capital and non-capital costs.

Reference Tariff	c/revenue meter/day
RT16	14.553
RT17	14.743
RT18	14.743
RT19	14.743
RT20	14.743
RT21	14.743
RT22	14.743
RT34	8.606
RT35	8.154
RT36	8.606
RT37	8.154
RT38	14.743
RT39	14.743
RT40	14.743
RT41	14.743
TRT1, TRT2 and TRT3	947.708

Table 8.15: Metering reference service prices

Metering Reference Service	c/revenue meter/day
M1	2.479
M2	2.479
M3	28.293
M4	56.588
M5	15.119
M6	15.119
M7 - SIM	131.065
M7 - AMI	2.479
M8	2.479
M9	2.479
M10	28.293
M11	56.588
M12	15.119
M13	15.119

Metering Reference Service	c/revenue meter/day
M14 - SIM	131.065
M14 - AMI	2.479
M15	50.262
M17	50.262
M18	50.262
M19	50.262
M20	50.262

Table 8.16: Metering reference service prices

Metering Reference Service	Charge per site visit ($)
M16	24.130

8.2.4 Administration charges

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

Table 8.17: Administration charges for RT7 and RT8

CMD	Price (c/day)
<7,000 kVA	5,479.275
>=7,000 kVA	9,542.775

8.2.5 LV prices

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

Table 8.18: LV prices RT8

Bundled Tariff	Fixed Price	Demand
	c/day	c/kVA
RT8	1,140.549	10.310

8.2.6 Connection price

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

Table 8.19: Connection Price RT11

	Connection Price (c/kW/day)
Connection price	2.317

8.3 Transmission prices

8.3.1 Use of system prices

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

Table 8.20: Transmission prices TRT1

Substation	TNI	Use of System Price (c/kW/day)
Albany	WALB	18.863
Alcoa Pinjarra	WAPJ	5.350
Amherst	WAMT	4.490
Arkana	WARK	5.731
Australian Fused Materials	WAFM	3.721
Australian Paper Mills	WAPM	5.802
Baandee (WC)	WBDE	20.219
Balcatta	WBCT	5.872
Beckenham	WBEC	14.813
Beechboro	WBCH	5.215
Beenup	WBNP	22.621
Belmont	WBEL	4.621
Bentley	WBTY	6.015
Bibra Lake	WBIB	4.131
Binningup Desalination Plant	WBDP	3.191
Black Flag	WBKF	20.618
Boddington	WBOD	3.373
Boddington Gold Mine	WBGM	3.461
Boulder	WBLD	18.176
Bounty	WBNY	44.651
Bridgetown	WBTN	9.238
British Petroleum	WBPM	7.977
Broken Hill Kwinana	WBHK	6.225
Bunbury Harbour	WBUH	3.051
Busselton	WBSN	9.555
Byford	WBYF	4.129
Canning Vale	WCVE	4.722

Substation	TNI	Use of System Price (c/kW/day)
Capel	WCAP	7.225
Carrabin	WCAR	23.358
Cataby Kerr McGee	WKMC	8.616
Chapman	WCPN	13.442
Clarence Street	WCLN	7.758
Clarkson	WCKN	5.851
Cockburn Cement	WCCT	3.243
Cockburn Cement Ltd	WCCL	3.233
Collie	WCOE	13.052
Collier	WCOL	7.722
Cook Street	WCKT	5.556
Coolup	WCLP	16.183
Cottesloe	WCTE	6.017
Cunderdin	WCUN	17.689
Darlington	WDTN	5.948
Edgewater	WEDG	5.152
Edmund Street	WEDD	5.301
Eneabba	WENB	9.679
Forrest Ave	WFRT	7.768
Forrestfield	WFFD	6.090
Geraldton	WGTN	11.032
Glen Iris	WGNI	3.599
Golden Grove	WGGV	28.915
Gosnells	WGNL	4.902
Hadfields	WHFS	5.891
Hay Street	WHAY	5.891
Hazelmere	WHZM	4.566
Henley Brook	WHBK	5.034
Herdsman Parade	WHEP	8.934
Joel Terrace	WJTE	8.109
Joondalup	WJDP	5.522
Kalamunda	WKDA	6.222

Substation	TNI	Use of System Price (c/kW/day)
Katanning	WKAT	15.120
Kellerberrin	WKEL	19.385
Kewdale	WKDL	4.530
Kojonup	WKOJ	6.918
Kondinin	WKDN	8.348
Kwinana Alcoa	WAKW	1.431
Kwinana Desalination Plant	WKDP	3.930
Kwinana PWS	WKPS	2.870
Landsdale	WLDE	5.310
Maddington	WMDN	4.771
Malaga	WMLG	4.535
Mandurah	WMHA	3.895
Manjimup	WMJP	9.071
Manning Street	WMAG	6.595
Margaret River	WMRV	15.217
Marriott Road	WMRR	2.556
Marriott Road Barrack Silicon Smelter	WBSI	2.918
Mason Road	WMSR	2.278
Mason Road CSBP	WCBP	3.445
Mason Road Kerr McGee	WKMK	2.088
Meadow Springs	WMSS	4.418
Medical Centre	WMCR	6.989
Medina	WMED	3.289
Merredin 66kV	WMER	16.496
Midland Junction	WMJX	5.551
Milligan Street	WMIL	6.580
Moora	WMOR	9.291
Morley	WMOY	6.052
Mt Barker	WMBR	16.415
Muchea	WMUC	5.805
Muchea Kerr McGee	WKMM	8.766
Muja PWS	WMPS	1.745

Substation	TNI	Use of System Price (c/kW/day)
Mullaloo	WMUL	5.704
Mundaring Weir	WMWR	8.905
Munday	WMDY	6.148
Murdoch	WMUR	3.678
Myaree	WMYR	7.025
Narrogin	WNGN	20.012
Nedlands	WNED	6.579
North Beach	WNBH	5.872
North Fremantle	WNFL	5.906
North Perth	WNPH	5.012
Northam	WNOR	11.822
Nowgerup	WNOW	6.773
O'Connor	WOCN	6.127
Osborne Park	WOPK	6.368
Padbury	WPBY	5.949
Parkeston	WPKS	20.690
Parklands	WPLD	4.541
Piccadilly	WPCY	16.454
Picton 66kv	WPIC	4.205
Pinjarra	WPNJ	3.247
Rangeway	WRAN	12.511
Regans	WRGN	9.954
Riverton	WRTN	4.065
Rivervale	WRVE	6.320
Rockingham	WROH	3.483
Sawyers Valley	WSVY	9.866
Shenton Park	WSPA	6.844
South Fremantle 22kV	WSFT	4.425
Southern River	WSNR	4.268
Summer St	WSUM	8.370
Sutherland	WSRD	5.012
Tate Street	WTTS	7.067

Substation	TNI	Use of System Price (c/kW/day)
Three Springs	WTSG	9.228
Three Springs Terminal (Karara)	WTST	22.284
Tomlinson Street	WTLN	7.160
University	WUNI	7.588
Victoria Park	WVPA	6.909
Wagerup	WWGP	2.544
Wagin	WWAG	15.496
Waikiki	WWAI	3.807
Wangara	WWGA	5.453
Wanneroo	WWNO	5.738
Wellington Street	WWNT	8.328
Welshpool	WWEL	4.503
Wembley Downs	WWDN	6.719
West Kalgoorlie	WWKT	15.041
Western Collieries	WWCL	2.561
Western Mining	WWMG	3.010
Westralian Sands	WWSD	6.551
Willetton	WWLN	4.327
Worsley	WWOR	2.125
Wundowie	WWUN	12.059
Yanchep	WYCP	5.747
Yerbillon	WYER	22.459
Yilgarn	WYLN	16.869
Yokine	WYKE	6.224

The prices in the following table are applicable for reference tariffs **RT11**, **TRT2** and **TRT3**.

Table 8.21: Reference tariffs RT11, TRT2 and TRT3

Substation	TNI	Use of System Price (c/kW/day)
Albany	WALB	2.418
Alcoa Pinjarra	WAPJ	2.150
Badgingarra	WBGA	2.466

Substation	TNI	Use of System Price (c/kW/day)
Bluewaters	WBWP	2.433
Boulder	WPCY	1.751
Cockburn	WCKB	1.475
Collgar	WCGW	2.793
Collie	WCPS	2.830
Emu Downs	WEMD	2.466
Geraldton	WGTN	0.414
Mungarra	TMGS	0.527
Kemerton	WKEM	1.966
Kwinana Alcoa	WAKW	1.521
Kwinana Donaldson Road	WKND	1.156
Kwinana	WKPS	1.475
Landwehr Terminal	WLWT	1.836
Mason Road	WMSR	1.156
Merredin Power Station	TMDP	2.033
Merredin Solar Farm	WMSF	2.033
Muja	WMPS	2.970
Mumbida	TMBW	2.502
Mungarra GTs	WMGA	2.458
Newgen Kwinana	WNGK	1.716
Newgen Neerabup	WGNN	1.512
Oakley	WOLY	2.047
Parkeston	WPKS	2.111
Pinjar	WPJR	1.227
Tiwest GT	WKMK	1.192
Wagerup	WWGP	1.692
Walkaway	WWWF	2.714
Warradarge Wind Farm	WWDW	2.466
West Kalgoorlie GTs	WWKT	1.716
Worsley	WWOR	1.922

Substation	TNI	Use of System Price (c/kW/day)
Yandin Wind Farm	WYDW	1.512

8.3.2 Common service prices

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

Table 8.22: Common Service Prices TRT1

	Common Service Price (c/kW/day)
Common service price	5.632

8.3.3 Control system service prices

The prices in the following table are applicable for reference tariffs **RT11**, **TRT2** and **TRT3**.

Table 8.23: Control system service prices for reference tariffs RT11, TRT2 and TRT3

	Price (c/kW/day)
Control system service price (Generators)	0.238

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

Table 8.24: Control system service prices for reference tariff TRT1

	Price (c/kW/day)
Control system service price (Loads)	2.113

8.4 Excess network usage charges – substation classification

The following table applies to reference tariffs **RT7, RT8, RT11, TRT1, TRT2** and **TRT3**.

Table 8.25: Values for ENUM for reference tariffs RT7, RT8, RT11, TRT1, TRT2 and TRT3

TNI	ENUM
ALB, BKF, BLD, BNY, PCY, PKS, WKT	2.5
All other substations	1

8.5 Other prices

The following table applies to reference tariff **RT25**.

Table 8.26: Supply abolishment charges for RT25

Location	Charge ($)
Whole current meters metropolitan area[9]	500.901
Whole current meters non-Metropolitan area	638.013
Non- whole current meters	User specific charge which reflects the costs to Western Power of undertaking the requested supply abolishment requested by the user and may consist of capital and non-capital costs.

The following table applies to reference tariffs **RT28 and RT29**.

Table 8.27: Charges for RT28 and RT29

Service	Charge per request ($)
RT28	6.146
RT29	6.146

The following table applies to reference tariffs **RT31**, **RT32**, and **RT33**.

Table 8.28: Metering prices for manual services

Metering Reference Service		Metropolitan Charge per site visit ($)	Country Metropolitan Charge per site visit ($)	Country Charge per site visit ($)
RT31	AMS standard	21.427	26.338	37.196
	AMS urgent	85.843	127.112	172.947
RT32	Standard	69.590	69.590	69.590
RT33	Standard	69.570	69.570	69.570
	Urgent	175.580	175.580	175.580

9 As defined in the Electricity Industry (Metering) Code

9. Applications and Queuing Policy fees

The Applications and Queuing Policy refers to several fees being published in the Price List. These prices are detailed below:

Table 9.1: Fees payable under the Applications and Queuing Policy

Fee type	Price
New Standard Access Contract Fee	$1,150.00
Access Contract Modification Fee	$140 per modification
Enquiry Fee	$3,500.00
Application Lodgement Fee	$5,000.00
Preliminary Offer Processing Fee	A variable fee
Preliminary Acceptance Fee	A variable fee
Distributed energy or other non-network solution assessment fee (B3 or C15)	A variable fee
Capacity allocation service fee – for a capacity swap reference service (D2)	$1,750.00
Remote load control/limitation (D6/RT26)	$6.146 per request

Table 9.2: Fees payable under the Applications and Queuing Policy

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 C5 – High Voltage Metered Demand Bi-directional Service	$44.00 per connection point
A6 – Low Voltage Metered Demand Exit Service C6 – Low Voltage Metered Demand Bi-directional Service	$44.00 per connection point
A7 – High Voltage Contract Maximum Demand Exit Service C7 – High Voltage Contract Maximum Demand Bi-directional Service	$88.00 per connection point
A8 – Low Voltage Contract Maximum Demand Exit Service C8 – Low Voltage Contract Maximum Demand Bi-directional Service	$88.00 per connection point
A9 – Streetlighting Exit Service	$0.00 per connection point
A10 – Unmetered 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

Application for Reference Service	New Connection Point Fee
B2 – Transmission Entry Service	$175.00 per connection point
B3 – Entry Service Facilitating a Distributed Generation or Other Non-Network Solution	$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
A12 – 3 Part Time of Use Energy (Residential) Exit Service C9 – 3 Part Time of Use Energy (Residential) Bi-directional Service	$0.00 per connection point
A13 – 3 Part Time of Use Energy (Business) Exit Service C10 – 3 Part Time of Use Energy (Business) Bi-directional Service	$0.00 per connection point
A14 – 3 Part Time of Use Demand (Residential) Exit Service C11 – 3 Part Time of Use Demand (Residential) Bi-directional Service	$0.00 per connection point
A15 – 3 Part Time of Use Demand (Business) Exit Service C12 – 3 Part Time of Use Demand (Business) Bi-directional Service	$0.00 per connection point
A16 – Multi Part Time of Use Energy (Residential) Exit Service C13 – Multi Part Time of Use Energy (Residential) Bi-directional Service	$0.00 per connection point
A17 – Multi Part Time of Use Energy (Business) Exit Service C14 – Multi Part Time of Use Energy (Business) Bi-directional Service	$0.00 per connection point
C15 – Bi-directional Service Facilitating a Distributed Generation or Other Non-Network Solution	$175.00 per connection point
A18 – Super Off-Peak Time of User Energy (Residential) Exit Service C16 – Super Off-Peak Time of User Energy (Residential) Bidirectional Service	$0.00 per connection point
A19 – Super Off-Peak Time of User Energy (Business) Exit Service C17 – Super Off-Peak Time of User Energy (Business) Bidirectional Service	$0.00 per connection point
A20 – Super Off-Peak Time of User Demand (Residential) Exit Service C18 – Super Off-Peak Time of User Demand (Residential) Bidirectional Service	$0.00 per connection point
A21 – Super Off-Peak Time of User Demand (Business) Exit Service C19 – Super Off-Peak Time of User Demand (Business) Bidirectional Service	$0.00 per connection point
A22 – Low Voltage Electric Vehicle Demand Exit Service C20 – Low Voltage Electric Vehicle Demand Bidirectional Service	$44.00 per connection point
A23 – High Voltage Electric Vehicle Demand Exit Service C21 – High Voltage Electric Vehicle Demand Bidirectional Service	$88.00 per connection point
C22 – Transmission Connected Storage Bidirectional Service	$175.00 per connection point
C23 – Low Voltage Distribution Connected Storage Bidirectional Service	$44.00 per connection point

Application for Reference Service	New Connection Point Fee
C24 – High Voltage Distribution Connected Storage Bidirectional Service	$88.00 per connection point

The AQP includes two variable fees, the preliminary offer processing fee and preliminary acceptance fee. The methodology for these fees can be found on the following webpage:

https://westernpower.com.au/about/regulation/network-access-prices/

Appendix A

Supporting information

A.1 Access Code Compliance

This section outlines how Western Power's network tariffs for AA5 comply with the requirements of the Access Code in respect of the pricing principles.

A.1.1 Access Code requirements for TSS and pricing

Section 7.1B(a) of the Access Code specifies that Western Power's TSS must comply with the pricing principles. These pricing principles are set out in sections 7.3D to 7.3L.

The pricing objective specified in section 7.3 of the Access Code requires Western Power's reference tariffs that it charges in respect of its provision of reference services should reflect Western Power's efficient costs of providing those services.

The Access Code pricing principles are:

Pricing principles

7.3D For each reference tariff, the revenue expected to be recovered must lie on or between:

(a) an upper bound representing the stand-alone cost of service provision for customers to whom or in respect of whom that reference tariff applies; and

(b) a lower bound representing the avoidable cost of not serving the customers to whom or in respect of whom that reference tariff applies.

7.3E The charges paid by, or in respect of, different customers of a reference service may differ only to the extent necessary to reflect differences in the average cost of service provision to the customers.

7.3F The structure of reference tariffs must, so far as is consistent with the Code objective, accommodate the reasonable requirements of users collectively and end-use customers collectively.

7.3G Each reference tariff must be based on the forward-looking efficient costs of providing the reference service to which it relates to the customers currently on that reference tariff with the method of calculating such cost and the manner in which that method is applied to be determined having regard to:

(a) the additional costs likely to be associated with meeting demand from end-use customers that are currently on that reference tariff at times of greatest utilisation of the relevant part of the service provider's network; and

(b) The location of end-use customers that are currently on that reference tariff and the extent to which costs vary between different locations in the service provider's network.

7.3H The revenue expected to be recovered from each reference tariff must:

(a) reflect the service provider's total efficient costs of serving the customers that are currently on that reference tariff.

(b) when summed with the revenue expected to be received from all other reference tariffs, permit the service provider to recover the expected revenue for the reference services in accordance with the service provider's access arrangement; and

(c) comply with sections 7.3H(a) and 7.3H(b) in a way that minimises distortions to price signals for efficient usage that would result from reference tariffs that comply with the pricing principle set out in section 7.3G.

7.3I The structure of each reference tariff must be reasonably capable of being understood by customers that are currently on that reference tariff, including enabling a customer to predict the likely annual changes in reference tariffs during the access arrangement period, having regard to:

(a) the type and nature of those customers;

(b) The information provided to, and the consultation undertaken with, those customers.

7.3J A reference tariff must comply with this Code and all relevant written laws and statutory instruments.

7.3K Despite sections 7.3D to 7.3H, a reference tariff may include a component, applicable where a user exceeds its contractual entitlements to transfer electricity into or out of the network at a connection point, which component is not set by reference to the service provider's costs, but instead is set at a level to act as a disincentive to the user exceeding its contractual entitlements. Such component should be determined having regard to the following principles:

(a) the component must be set at a level which provides a material disincentive to the user transferring into or out of the network quantities of electricity above its contractual entitlements; and

(b) in determining that level, regard is to be had to the potential adverse impact on the network, other customers and generators, and the service provider of the user transferring into or out of the network quantities of electricity above its contractual entitlements.

7.3L Unless otherwise determined by the Authority, section 7.3K does not apply to connection points servicing end use customers with a contract maximum demand not exceeding 1 MVA or end-use customers with solar photovoltaic generating plant not exceeding 1 MVA in capacity.

Tariff components

7.6 Unless a tariff structure statement containing alternative pricing methods would better achieve the Code objective, and subject to section 7.3K, for a reference service:

(a) the incremental cost of service provision should be recovered by tariff components that vary with usage or demand; and

(b) any amount in excess of the incremental cost of service provision should be recovered by tariff components that do not vary with usage or demand.

A.1.2 Access Code requirements for the price list

Section 8.12 of the Access Code outlines the obligations on Western Power with respect to the contents of the price list.

Contents of price list

8.12 A price list must:

(a) set out the proposed *reference tariffs* for the relevant *access arrangement period*;

(b) set out, for each proposed *reference tariff*, the *charging parameters,* and the elements of service to which each *charging parameter* relates;

(c) set out the nature of any variation or adjustment to the *reference tariff* that could occur during the course of the *pricing year* and the basis on which it could occur;

(d) demonstrate compliance with this Code and the *service provider's access arrangement*, including the *service provider's tariff structure statement* for the relevant *access arrangement period*;

(e) for any *pricing year* other than the first *pricing year* in an *access arrangement period*, demonstrate how each proposed *reference tariff* is consistent with the corresponding forecast price change for that *reference tariff* for the relevant *pricing year* as set out in the relevant *reference tariff change forecast*, or explain any material differences between them; and

(f) describe the nature and extent of change from the previous *pricing year* and demonstrate that the changes comply with this Code and the *service provider's access arrangement*.

Revision of reference tariff change forecast

8.13 At the same time as a *service provider* submits a *price list* under section 8.1, the *service provider* must submit to the *Authority* a revised *reference tariff change forecast* which sets out, for each *reference tariff*, the *service provider's* forecast of the weighted average annual price change for that *reference tariff* for each remaining pricing year of the *access arrangement period* and updated so as to take into account that *price list*.

Publication of information about tariffs

8.14 A *service provider* must maintain on its website:

(a) its current *tariff structure statement*;

(b) its current *reference tariff change forecast*; and

(c) its current approved *price list*.

8.15 A *service provider* must, within 5 *business days* from the date the *Authority publishes* its *final decision* under section 4.17 for that *service provider's access arrangement*, *publish* the *tariff structure statement* approved or contained in the approved *access arrangement* and the accompanying *reference tariff change forecast*.

8.16 A *service provider* must *publish* the information referred to in section 8.14 within 5 *business days* from the date the *Authority publishes* an *approved price list* under section 8.1A, section 8.6 or section 8.7 (as applicable) for that *service provider*.

A.1.3 Compliance with the Access Code pricing principles

This section demonstrates Western Power's compliance with the pricing principles set out in sections 7.3D to 7.3L of the Access Code. In particular, the pricing principles set out in sections 7.3D, 7.3G, 7.3H, 7.3I and 7.6.

Section 7.3D stand-alone and avoidable costs

Section 7.3D of the Access Code requires Western Power to ensure that the revenue recovered for each reference tariff lies between:

(a) an upper bound representing the stand-alone cost of service provision for customers to whom or in respect of whom that reference tariff applies; and

(b) a lower bound representing the avoidable cost of not serving the customers to whom or in respect of whom that reference tariff applies.

The stand-alone and avoidable cost methodologies are consistent with those used for the 2022-27 TSS. These approaches are used to calculate the revenues for each reference tariff associated with each cost methodology. These costs are compared with the expected revenue to be recovered from Western Power's proposed reference tariffs.

The revenue expected to be recovered from each of Western Power's reference tariffs in 2023-24 is compared with the stand-alone and avoidable costs in Table A.1.

Table A.1 Demonstration Reference Tariffs are between avoidable and stand-alone cost of service provision for 2023-24 ($M Nominal)

Reference Service	Reference Tariff	Avoidable Cost	Stand-alone Cost	Forecast Revenue Recovered from Reference Tariff
A1	RT1	32.57	866.13	265.03
A2	RT2	12.34	756.49	62.19
A3	RT3	0.56	706.03	4.64
A4	RT4	5.07	725.70	14.68
A5, C5	RT5	6.77	522.74	47.52
A6, C6	RT6	26.98	810.91	129.35
A7, C7	RT7	26.75	598.46	172.47
A8, C8	RT8	2.55	714.11	24.59
A9	RT9	20.60	703.92	62.08
A10	RT10	0.67	706.15	6.62
B1	RT11	0.62	706.15	4.97
C1	RT13	18.32	777.60	140.32
C2	RT14	0.68	706.20	6.48
C3	RT15	1.26	708.34	6.18
C4	RT16	2.13	712.13	3.19
A12, C9	RT17	32.15	843.73	139.69
A13, C10	RT18	38.15	859.44	199.53
A14, C11	RT19	0.29	705.74	0.29

Reference Service	Reference Tariff	Avoidable Cost	Stand-alone Cost	Forecast Revenue Recovered from Reference Tariff
A15, C12	RT20	18.15	788.29	47.54
A16, C13	RT21	122.25	1141.91	233.75
A17, C14	RT22	0.26	704.63	1.38
A19, C17	RT34	8.75	735.39	15.33
A18, C16	RT35	16.20	757.19	83.41
A21, C19	RT36	1.49	708.89	11.24
A20, C18	RT37	2.12	710.49	13.39
C23	RT38	0.00	703.47	1.05
C24	RT39	0.00	495.85	1.05
A22, C20	RT40	0.01	703.51	0.09
A23, C21	RT41	0.00	495.85	0.06
A11	TRT1	2.30	410.34	48.89
B2	TRT2	2.30	79.76	58.57
C22	TRT3	2.30	69.43	1.05[10]

Tariffs reflect forward-looking efficient costs

Section 7.3G of the Access Code requires each reference tariff to be based on the forward-looking efficient costs of providing the reference service to which it relates to the customers currently on that reference tariff with the method of calculating such cost and the manner in which that method is applied to be determined having regard to:

a. the additional costs likely to be associated with meeting demand from end-use customers that are currently on that reference tariff at times of greatest utilisation of the relevant part of the service provider's network; and

b. the location of end-use customers that are currently on that reference tariff and the extent to which costs vary between different locations in the service provider's network.

Table A.2 below outlines how Western Power allocates the revenue across its customer groups in accordance with sections 3.1 and 3.2 of the tariff structure statement under the approved AA5 access arrangement. Western Power's process ensures that tariffs reflect the efficient costs incurred in supplying customers using those tariffs.

10 Western Power notes this is a new tariff, and we are unsure of the likely uptake of it over AA5. As such, for this first pricing year the expected revenue falls below the avoidable costs of supplying customers on this service. As more information becomes available over AA5, Western Power will endeavour recover revenue above the avoided costs.

Table A.2 Cost allocation of distribution and transmission target revenue to relevant customer groups and cost pools for 2023-24 ($M nominal)

Customer groups	Distribution Revenue							Transmission Revenue included in Distribution	Bundled Revenue	Proportion of total costs
	High voltage	Low voltage	Transformers	Metering	Streetlights	Admin	Total			
Residential	417.82	352.39	48.09	30.01	0.00	84.00	**932.31**	268.40	**932.31**	51.60%
LV business - small	178.91	141.79	15.97	18.54	0.00	51.91	**407.12**	95.25	**407.12**	22.54%
LV business - large	71.45	7.46	6.90	5.08	0.00	14.22	**105.11**	23.42	**105.11**	5.82%
HV business	135.60	14.06	11.59	10.41	0.00	29.15	**200.82**	45.03	**200.82**	11.12%
Streetlights	0.00	0.39	0.00	0.00	46.26	0.00	**46.65**	0.13	**46.65**	2.58%
Unmetered	0.70	1.63	0.08	0.00	0.00	0.11	**2.51**	0.83	**2.51**	0.14%
Generators	2.06	1.33	0.21	0.00	0.00	0.00	**3.61**	0.00	**3.61**	0.20%
Transmission	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**	108.51	**108.51**	6.01%
Total	**806.55**	**519.05**	**82.84**	**64.05**	**46.26**	**179.38**	**1,698.13**	**541.57**	**1,806.63**	**100.00%**

Distribution revenue of $1,698 million is allocated across the distribution customer groups (and subsequently the reference tariffs) according to the usage by customers of the various voltage steps (represented by asset categories) involved. Under Western Power's cost allocation methodology, the proportion of low voltage cost allocation determined by demand is equal to 50 per cent.

The efficient costs are apportioned across these asset categories, with customers' use of these assets determined by the customers' diversified demand and usage. Some assets are apportioned according to customer numbers, for example connection services.

Revenue expected to be recovered from reference tariffs

Section 7.3H of the Access Code requires the revenue expected to be recovered from reference tariffs to:

a. reflect the service provider's total efficient costs of serving the customers that are currently on that reference tariff;

b. when summed with the revenue expected to be received from all other reference tariffs, permit the service provider to recover the expected revenue for the reference services in accordance with the service provider's access arrangement; and

c. comply with sections 7.3H(a) and 7.3H(b) in a way that minimises distortions to the price signals for efficient usage that would result from reference tariffs that comply with the pricing principle set out in section 7.3G.

Table A.3 below demonstrates how the cost allocation of distribution and transmission target revenues to the relevant customer groups and cost pools has been allocated to the individual reference tariffs in a manner that when summed permits Western Power to recover the expected revenue for the reference services in accordance with the energy and customer numbers codified under the access arrangement.

Table A.3 Bundled reference service revenue recovered from distribution and transmission connection points for 2023-24 ($M nominal)

Reference tariff	MWh	Customer numbers	Forecast bundled revenue recovered
RT1 – Anytime Energy (Residential)	1,753,990	287,519	265.03
RT2 – Anytime Energy (Business)	322,916	33,907	62.19
RT3 – Time of Use Energy (Residential)	30,676	4,032	4.64
RT4 – Time of Use Energy (Business)	101,229	3,056	14.68
RT5 – High Voltage Metered Demand	669,767	341	47.52
RT6 – Low Voltage Metered Demand	1,694,095	3,662	129.35
RT7 – High Voltage Contract Maximum Demand	3,343,382	344	172.47
RT8 – Low Voltage Contract Maximum Demand	239,283	86	24.59
RT9 – Streetlighting	138,422	293,180	62.08
RT10 – Unmetered Supplies	46,854	19,811	6.62
RT11 – Distribution Entry	197	25	4.97
RT13 – Anytime Energy (Residential) Bi-directional	961,201	144,862	140.32
RT14 – Anytime Energy (Business) Bi-directional	46,374	1,400	6.48
RT15 – Time of Use (Residential) Bi-directional	30,320	8,241	6.18
RT16 – Time of Use (Business) Bi-directional	20,769	627	3.19
RT17 – Time of Use Energy (Residential)	730,281	196,408	139.69
RT18 – Time of Use Energy (Business)	1,399,423	42,247	199.53
RT19 – Time of Use Demand (Residential)	1,607	249	0.29
RT20 – Time of Use Demand (Business)	209,944	6,338	47.54
RT21 – Multi Part Time of Use Energy (Residential)	1,210,348	327,817	233.75
RT22 – Multi Part Time of Use Energy (Business)	9,639	291	1.38
RT34 – Super Off-peak Time of Use Energy (Business)	75,779	10,910	15.33
RT35 – Super Off-peal Time of Use Energy (Residential)	430,597	118,527	83.41
RT36 – Super Off-peak Time of Use Demand (Business)	61,383	1,853	11.24
RT37 – Super Off-peak Time of Use Demand (Residential)	56,323	15,504	13.39
RT38 – Low Voltage Distribution Storage	0	1	1.05
RT39 – High Voltage Distribution Storage	0	1	1.05
RT40 – Low Voltage Electric Vehicle Charging	175	10	0.09
RT41 – High Voltage Electric Vehicle Charging	35	2	0.06
Total Bundled Target Revenue from distribution customers	**13,585,008**	**1,521,253**	**1,698.13**

Reference tariff	MWh	Customer numbers	Forecast bundled revenue recovered
TRT1 - Transmission exit	838	30	49
TRT2 - Transmission entry	5,654	26	59
TRT3 - Transmission storage	0	0	1
Total Bundled Target Revenue from transmission customers	**6,492**	**56**	**108.51**
Total Bundled Target Revenue	**13,591,500**	**1,521,309**	**1,806.63**

Incremental cost of service provision recovered by variable component of tariffs

Section 7.6 of the Access Code states that unless a tariff structure statement containing alternative pricing methods would better achieve the Code objective, and subject to section 7.3K, for a reference service:

c. the incremental cost (avoidable cost) of service provision should be recovered by tariff components that vary with usage or demand; and

d. any amount in excess of the incremental cost (avoidable cost) of service provision should be recovered by tariff components that do not vary with usage or demand.

Western Power has had regard to this requirement in setting tariffs. The following Table A.4 shows that the variable components for 2023-24 tariffs exceeds the avoidable cost calculated for the comparison of stand-alone and avoidable costs above, with the exception of reference tariff RT9 for streetlights which is priced lower than the avoidable cost.

Table A.4 Demonstration that variable costs exceed avoidable costs of reference tariff provision for 2023-24 ($M nominal)

Reference Service	Reference Tariff	Avoidable Cost	Variable tariff components
A1	RT1	32.57	152.12
A2	RT2	12.34	38.20
A3	RT3	0.56	3.04
A4	RT4	5.07	10.66
A5, C5	RT5	6.77	18.47
A6, C6	RT6	26.98	83.31
A7, C7	RT7	26.75	101.79
A8, C8	RT8	2.55	5.72
A9	RT9	20.60	7.195 ^
A10	RT10	0.67	2.27
B1	RT11	0.62	4.96
C1	RT13	18.32	83.36
C2	RT14	0.68	5.49

Reference Service	Reference Tariff	Avoidable Cost	Variable tariff components
C3	RT15	1.26	2.92
C4	RT16	2.13	2.22
A12, C9	RT17	32.15	57.64
A13, C10	RT18	38.15	168.62
A14, C11	RT19	0.29	0.18 *
A15, C12	RT20	18.15	41.23
A16, C13	RT21	122.25	97.14 ^^
A17, C14	RT22	0.26	1.16
A19, C17	RT34	8.75	7.62 **
A18, C16	RT35	16.20	36.93
A21, C19	RT36	1.49	8.90
A20, C18	RT37	2.12	7.31
C23	RT38	0.00	1.05
C24	RT39	0.00	1.05
A22, C20	RT40	0.01	0.08
A23, C21	RT41	0.00	0.05

Notes: ^ inclusion of the fixed asset charge in the avoidable cost stack for streetlights has led to the variable tariff component being lower than the avoidable cost.
* RT19 has a very low number of customers on it and the pricing principle to keep all fixed charges constant across residential tariffs results in the variable tariff component being lower than the avoidable costs.
^^ RT21 has variable components that are currently set below cost reflectivity. As Western Power transitions this tariff towards greater cost reflectivity over AA5, we expect the variable tariff component to increase above avoidable costs.
** RT34 has been newly introduced for AA5 and Western Power considers the amount of revenue recovered from variable tariff components will increase as users churn end-use small business consumers onto this tariff.

A.1.4 Compliance with the Access Code price list requirements

This section demonstrates Western Power's compliance with the pricing list requirements set out in sections 8.12 and 8.13 of the Access Code.

Contents of the price list

Section 2 of this price list sets out the reference services and associated tariffs Western Power intends to provide to users over AA5.

Sections 5, 6 and 7 of this price list provide a technical breakdown of each reference tariff into each of its component parts, charging windows and the elements of service to which each charging parameter relates.

Sections 5, 6 and 7 of this price list provide information to users on the variations or adjustments that may occur over the course of a pricing year. For example, information on excess network charging arrangements, and the process to update a user's metered maximum demand over a rolling 12-month period.

Section 1.4 demonstrates compliance with the form of price control formula contained within the approved *access arrangement contract*. Furthermore, Sections 1.6 and 5, 6 and 7 demonstrate compliance with the tariff structures contained in the tariff structure statement that forms part of the approved access arrangement.

As this price list forms the first pricing year for the AA5 access arrangement period, Western Power is not required to demonstrate compliance with the requirement for the weighted average price changes for each reference tariff to be consistent with the reference tariff change forecast compared with the previous pricing year.

Revision of reference tariff change forecast

As set out in section 1.6, Western Power has submitted its revised reference tariff change forecast In accordance with section 8.13 of the Access Code. The revised reference tariff change forecast sets out the weighted average annual price change for each reference tariff for each remaining pricing year of AA5 and has been updated to reflect the prices contained within this price list.

A.2 Extracts from Western Power's pricing model

The TSS sets out the detailed methodology which allocates total revenue into transmission and distribution 'cost pools' and then allocates these cost pools to customer groups and ultimately tariffs. Below are several extracts from the pricing model updated for 2023-24.

A.2.1 Transmission pricing cost pools

The following sets out the allocation of revenue to the transmission cost pools for the 2023-24 pricing year.

Table A.5 - Transmission Pricing Cost Pools for 2023-24 ($M Nominal)

Cost Pool	Allocated Revenue
Entry connection	11.57
Exit connection HV	2.71
Exit connection LV	144.65
CSS entry	5.06
CSS exit	36.37
UOS entry	41.31
UOS exit	114.37
Common service	185.28
Metering CT/VT	0.23
Total	**541.57**

A.2.2 Distribution pricing cost pools

Applying the distribution pricing methodology, the following tables details the allocation of the distribution network revenue entitlement (which includes TEC) to the cost pools:

Table A.6: -Distribution Cost Pools for 2023-24 ($M Nominal)

Cost Pool	Locational Zone					
	CBD	Urban	Mining	Mixed	Rural	Total
High Voltage Network	5.46	190.66	9.78	240.10	360.55	**806.55**
Low Voltage Network	6.46	334.59	0.25	121.58	56.17	**519.05**
Transformers	2.42	38.78	0.28	23.04	18.31	**82.84**
Streetlight Assets	0.65	25.65	0.47	17.49	19.78	**64.05**
Metering	0.47	18.53	0.34	12.64	14.29	**46.26**
Administration	1.83	71.84	1.31	49.00	55.41	**179.39**
Revenue requirement	**17.30**	**680.03**	**12.44**	**463.86**	**524.50**	**1,698.13**

Table A.7: Derivation of Streetlight and Metering Costs ($M Nominal)

2023-24 cost of service	Streetlights	Metering
Opening RAB	152.20	263.40
Return on asset	6.59	11.41
Depreciation	13.83	22.97
Opex	22.95	25.11
Indirect cost allocation	2.89	4.56
Cost of service	46.26	64.05

A.3 Customer bill impacts (network component of reference tariffs only)

Our desired price path for AA5, as explained in section 5.2 of the Tariff Structure Statement – Overview, applies to the average network revenue recovered from our customers. While this approach ensures that, on average, end-users network bill impacts are limited, some end-users may experience different outcomes due to the particular characteristics of their energy use.

In this section, we provide context to the potential network bill impacts on different types of end-users on each reference tariff. We present our network bill impacts as the rate of bill change, as a percentage, in nominal terms and have worked to remain within the constraints of our pricing strategy.

A.3.1 Residential end-users

As the network service provider does not assign end-users to a particular tariff, the network bill impact analysis focuses on the price impact between years for end-users on a particular reference tariff. Our bill impact analysis is performed on five distinct, representative residential end-users, including:

- a low consumption residential end-user – the 25th percentile of total annual energy consumption from our residential end-user sample;

- a medium consumption residential end-user – the median of total annual energy consumption from our residential end-user sample;
- a high consumption residential end-user – the 75th percentile of total annual energy consumption from our residential end-user sample;
- a typical residential end-user with solar – the median of total annual energy consumption from our residential end-user sample for end-users with solar installations only; and
- a typical residential end-user without solar – the median of total annual energy consumption from our residential end-user sample for end-users without solar installations.

RT1/RT13 – Anytime energy residential tariffs

The customer network bill impacts for RT1 and RT13 over AA5 is shown in Table A.8.

Table A.8: Annual network bill impacts over AA5 for RT1/RT13

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Annual change FY25 to FY26	Annual change FY23 to FY27	Annualised change over AA5
Low consumption end-user	0%	5%	553	5%	2%	2%	**3%**
Medium consumption end-user	0%	3%	678	4%	2%	2%	**3%**
High consumption end-user	0%	2%	820	3%	1%	1%	**2%**
Typical solar end-user	0%	3%	737	3%	2%	1%	**2%**
Typical non-solar end-user	0%	3%	669	4%	2%	2%	**3%**

RT3/RT15 – Time of use residential tariffs

The customer network bill impacts for RT3 and RT15 over AA5 is shown in Table A.9.

Table A.9: Annual network bill impacts over AA5 for RT3/RT15

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Annual change FY25 to FY26	Annual change FY23 to FY27	Annualised change over AA5
Low consumption end-user	0%	12%	599	9%	7%	7%	**9%**
Medium consumption end-user	0%	13%	757	10%	9%	9%	**10%**
High consumption end-user	0%	13%	932	11%	10%	10%	**11%**

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Annual change FY25 to FY26	Annual change FY23 to FY27	Annualised change over AA5
Typical solar end-user	0%	13%	809	11%	9%	9%	**11%**
Typical non-solar end-user	0%	13%	744	10%	9%	9%	**10%**

RT17 – 3 part time of use residential tariff

The customer network bill impacts for RT17 over AA5 is shown in Table A.10.

Table A.10: Annual network bill impacts over AA5 for RT17

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Annual change FY25 to FY26	Annual change FY23 to FY27	Annualised change over AA5
Low consumption end-user	0%	9%	560	10%	7%	8%	**8%**
Medium consumption end-user	0%	10%	670	11%	9%	10%	**10%**
High consumption end-user	0%	12%	795	12%	11%	11%	**11%**
Typical solar end-user	0%	11%	723	12%	10%	10%	**11%**
Typical non-solar end-user	0%	10%	662	11%	9%	9%	**10%**

RT19 – 3 part time of use demand residential tariff

The customer network bill impacts for RT19 over AA5 is shown in Table A.11.

Table A.11: Annual network bill impacts over AA5 for RT19

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Annual change FY25 to FY26	Annual change FY23 to FY27	Annualised change over AA5
Low consumption end-user	0%	12%	571	8%	5%	5%	**8%**
Medium consumption end-user	0%	13%	677	8%	6%	6%	**8%**
High consumption end-user	0%	14%	791	9%	7%	7%	**9%**

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Annual change FY25 to FY26	Annual change FY23 to FY27	Annualised change over AA5
Typical solar end-user	0%	14%	723	8%	7%	6%	**9%**
Typical non-solar end-user	0%	13%	668	8%	6%	6%	**8%**

RT21 – Multi part time of use residential tariff

The customer network bill impacts for RT19 over AA5 is shown in Table A.12.

Table A.12: Annual network bill impacts over AA5 for RT21

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Annual change FY25 to FY26	Annual change FY23 to FY27	Annualised change over AA5
Low consumption end-user	0%	12%	578	10%	8%	8%	**9%**
Medium consumption end-user	0%	13%	704	11%	9%	10%	**11%**
High consumption end-user	0%	14%	846	12%	11%	11%	**12%**
Typical solar end-user	0%	14%	761	12%	10%	10%	**11%**
Typical non-solar end-user	0%	13%	695	11%	9%	9%	**11%**

RT35 – Super off-peak time of use energy residential tariff

The customer network bill impacts for RT35 over AA5 is shown in Table A.13.

Table A.13: Annual network bill impacts over AA5 for RT35

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Annual change FY25 to FY26	Annual change FY23 to FY27	Annualised change over AA5
Low consumption end-user	0%	0%	529	5%	3%	2%	**3%**
Medium consumption end-user	0%	0%	637	4%	2%	2%	**3%**
High consumption end-user	0%	0%	758	4%	2%	1%	**2%**

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Annual change FY25 to FY26	Annual change FY23 to FY27	Annualised change over AA5
Typical solar end-user	0%	0%	714	4%	2%	2%	**2%**
Typical non-solar end-user	0%	0%	629	4%	2%	2%	**3%**

RT37 – Super off-peak time of use demand residential tariff

The customer network bill impacts for RT37 over AA5 is shown in Table A.14.

Table A.14: Annual network bill impacts over AA5 for RT37

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Annual change FY25 to FY26	Annual change FY23 to FY27	Annualised change over AA5
Low consumption end-user	0%	0%	520	5%	3%	2%	**3%**
Medium consumption end-user	0%	0%	611	4%	2%	2%	**3%**
High consumption end-user	0%	0%	709	4%	2%	2%	**2%**
Typical solar end-user	0%	0%	669	4%	2%	2%	**3%**
Typical non-solar end-user	0%	0%	603	4%	2%	2%	**3%**

A.3.2 Small business end-users

As with our residential end-users, our network bill impact analysis is performed on five distinct, representative small business end-users, including:

- a low consumption small business end-user – the 25th percentile of total annual energy consumption from our small business end-user customer sample;
- a medium consumption small business end-user – the median of total annual energy consumption from our small business end-user customer sample;
- a high consumption small business end-user – the 75th percentile of total annual energy consumption from our small business end-user customer sample;
- a typical small business end-user with solar – the median of total annual energy consumption from our small business end-user sample for end-users with solar installations only; and
- a typical small business end-user without solar – the median of total annual energy consumption from our small business end-user sample for end-users without solar installations

RT2/RT14 – Anytime energy business tariffs

The customer network bill impacts for RT2 and RT14 over AA5 is shown in Table A.15.

Table A.15: Annual network bill impacts over AA5 for RT2/RT14

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Annual change FY25 to FY26	Annual change FY23 to FY27	Annualised change over AA5
Low consumption end-user	5%	6%	917	5%	2%	2%	**4%**
Medium consumption end-user	3%	4%	1,314	3%	1%	1%	**2%**
High consumption end-user	2%	2%	1,996	2%	1%	1%	**2%**
Typical solar end-user	2%	3%	1,929	2%	1%	1%	**2%**
Typical non-solar end-user	2%	2%	2,282	2%	1%	1%	**1%**

RT4/RT16 – Time of use business tariffs

The customer network bill impacts for RT4 and RT16 over AA5 is shown in Table A.16.

Table A.16: Annual network bill impacts over AA5 for RT4/RT16

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Annual change FY25 to FY26	Annual change FY23 to FY27	Annualised change over AA5
Low consumption end-user	9%	7%	1,545	8%	5%	5%	**6%**
Medium consumption end-user	7%	9%	1,992	9%	7%	7%	**8%**
High consumption end-user	5%	11%	2,814	11%	9%	10%	**10%**
Typical solar end-user	6%	10%	2,434	10%	8%	9%	**9%**
Typical non-solar end-user	4%	11%	3,046	11%	10%	10%	**10%**

RT18 – 3 part time of use business tariff

The customer network bill impacts for RT18 over AA5 is shown in Table A.17.

Table A.17: Annual network bill impacts over AA5 for RT18

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Annual change FY25 to FY26	Annual change FY23 to FY27	Annualised change over AA5
Low consumption end-user	8%	9%	945	9%	6%	7%	**8%**
Medium consumption end-user	6%	11%	1,352	12%	10%	11%	**11%**
High consumption end-user	4%	12%	2,066	14%	13%	13%	**13%**
Typical solar end-user	4%	12%	1,973	14%	13%	13%	**13%**
Typical non-solar end-user	3%	13%	2,333	14%	13%	14%	**14%**

RT20 – 3 part time of use demand business tariff

The customer network bill impacts for RT20 over AA5 is shown in Table A.18.

Table A.18: Annual network bill impacts over AA5 for RT20

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Annual change FY25 to FY26	Annual change FY23 to FY27	Annualised change over AA5
Low consumption end-user	10%	15%	1,208	8%	5%	5%	**8%**
Medium consumption end-user	7%	15%	1,603	9%	7%	7%	**9%**
High consumption end-user	5%	15%	2,289	10%	8%	8%	**10%**
Typical solar end-user	5%	15%	2,181	10%	8%	8%	**10%**
Typical non-solar end-user	4%	15%	2,530	10%	9%	9%	**11%**

RT22 – Multi part time of use energy business tariff

The customer network bill impacts for RT22 over AA5 is shown in Table A.19.

Table A.19: Annual network bill impacts over AA5 for RT22

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Annual change FY25 to FY26	Annual change FY23 to FY27	Annualised change over AA5
Low consumption end-user	11%	8%	964	9%	6%	6%	**7%**
Medium consumption end-user	7%	9%	1,384	11%	10%	10%	**10%**
High consumption end-user	5%	11%	2,128	13%	12%	12%	**12%**
Typical solar end-user	5%	11%	1,983	13%	12%	12%	**12%**
Typical non-solar end-user	4%	11%	2,392	14%	13%	13%	**13%**

RT34 – Super off-peak time of use energy business tariff

The customer network bill impacts for RT34 over AA5 is shown in Table A.20.

Table A.20: Annual network bill impacts over AA5 for RT34

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Annual change FY25 to FY26	Annual change FY23 to FY27	Annualised change over AA5
Low consumption end-user	0%	0%	875	5%	2%	2%	**4%**
Medium consumption end-user	0%	0%	1,193	4%	2%	1%	**3%**
High consumption end-user	0%	0%	1,737	3%	2%	1%	**2%**
Typical solar end-user	0%	0%	1,806	3%	2%	1%	**2%**
Typical non-solar end-user	0%	0%	1,969	3%	2%	1%	**2%**

RT36 – Super off-peak time of use demand business tariff

The customer network bill impacts for RT36 over AA5 is shown in Table A.21.

Table A.21: Annual network bill impacts over AA5 for RT36

Representative end-user	Annual change FY22 to FY23	Annual change FY23 to FY24	Baseline $/year FY24	Annual change FY24 to FY25	Annual change FY25 to FY26	Annual change FY23 to FY27	Annualised change over AA5
Low consumption end-user	0%	0%	1,434	5%	2%	2%	**12%**
Medium consumption end-user	0%	0%	1,752	5%	2%	2%	**10%**
High consumption end-user	0%	0%	2,292	4%	2%	1%	**7%**
Typical solar end-user	0%	0%	2,317	4%	2%	1%	**7%**
Typical non-solar end-user	0%	0%	2,507	3%	2%	1%	**7%**

A.4 TEC in the Components of Reference Tariffs

This section details the amounts associated with TEC that are embedded within the 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 previous sections are inclusive of TEC. The tables that follow in this section separate out the amounts of TEC that are embedded within the distribution reference tariff components.

A.4.1 TEC Forecast Revenue

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

Table A.22: TEC Recovered from Distribution Connection Points for 2023-24 ($M Nominal)

Reference Tariff	kWh	Number Customers	Forecast TEC Recovered
RT1 - Anytime Energy (Residential)	1,753,990,089	287,519	32.10
RT2 - Anytime Energy (Business)	322,915,754	33,907	6.05

Reference Tariff	kWh	Number Customers	Forecast TEC Recovered
RT3 - Time of Use Energy (Residential)	30,675,868	4,032	0.48
RT4 - Time of Use Energy (Business)	101,228,770	3,056	1.59
RT5 - High Voltage Metered Demand	669,767,419	341	13.98
RT6 - Low Voltage Metered Demand	1,694,094,832	3,662	13.57
RT7 - High Voltage Contract Maximum Demand	3,343,381,804	344	7.43
RT8 - Low Voltage Contract Maximum Demand	239,282,745	86	2.54
RT9 – Streetlighting	138,422,170	293,180	1.00
RT10 - Unmetered Supplies	46,854,217	19,811	0.36
RT11 - Distribution Entry	196,745	25	Not Applicable
RT13 – Anytime Energy (Residential) Bi-directional	961,200,980	144,862	17.59
RT14 – Anytime Energy (Business) Bi-directional	46,374,436	1,400	0.87
RT15 – Time of Use (Residential) Bi-directional	30,319,612	8,241	0.46
RT16 – Time of Use (Business) Bi-directional	20,769,123	627	0.33
RT17 - Time of Use Energy (Residential)	730,280,521	196,408	12.85
RT18 - Time of Use Energy (Business)	1,399,423,147	42,247	25.13
RT19 – Time of Use Demand (Residential)	1,606,961	249	0.03
RT20 – Time of Use Demand (Business)	209,944,361	6,338	3.64
RT21 – Multi Part Time of Use Energy (Residential)	1,210,347,940	327,817	21.55
RT22 – Multi Part Time of Use Energy (Business)	9,639,258	291	0.17
RT34 – Super Off-peak Time of Use Energy (Business)	75,778,620	10,910	1.34
RT35 – Super Off-peal Time of Use Energy (Residential)	430,596,682	118,527	7.85
RT36 – Super Off-peak Time of Use Demand (Business)	61,382,595	1,853	1.09
RT37 – Super Off-peak Time of Use Demand (Residential)	56,323,230	15,504	1.03
RT40 – Low Voltage Electric Vehicle Charging	174,878	10	0.00
RT41 – High Voltage Electric Vehicle Charging	34,976	2	0.00
Total	**13,585,007,730**	**1,521,251**	**173.00**

Appendix B

Policy for price setting new transmission nodes

B.1 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 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.

B.1.1 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. (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 1.82% of the full capital cost up to a maximum value of connection assets of $30 million, which will be reviewed by Western Power on an annual basis as part of the price list.

The 1.82 percentage is based on the average of the ratio of the forecast Operations and Maintenance cost and the closing regulatory asset base 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 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.