Western Power

PRICING STRUCTURE FOR THE TRANSMISSION AND DISTRIBUTION NETWORK BUSINESSES

Western Power Corporation

ABN 38 362 983 875

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1 Introduction

This document describes the process by which the Western Power network businesses develop network access prices for the south-west interconnected transmission and distribution networks. It is a part of the Access Arrangement to be submitted under the Access Code to the Economic Regulatory Authority to cover the regulatory period 2006/07 to 2008/09.

Pricing Objectives and Principles

Code Requirements

Under the provisions of chapter 7 of the Code, the pricing methods must meet a number of criteria. In particular:

- They must reflect the forward-looking efficient costs of providing reference services. The lower end of the price band should equal or exceed the incremental cost of service provision, and the highest price should be equal to or less than the stand-alone cost of service provision.

- The incremental cost of service provision should be recovered by tariff components that vary with usage or demand.

- 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.

Any charges paid by customers that departs from these principles must:

- Be consistent with the code,

- Take into account differences in average costs of service provision,

- Accommodate the user's requirements, and

- Should avoid price shocks.

Uniform or "postage stamp" charges are required for customers with annual energy demand less than 1 MVA. There is also a requirement restricting any tariff re-balancing to once per year.

A methodology is required to calculate the value of any prudent discount including any reduction to access charges for recognition of network savings created specifically by the location of the generator in the network.

Network Tariffs

1.1.1 Background

A suite of tariffs is currently in place that are designed to recover the regulated revenue for both the transmission and distribution network businesses. The transmission and distribution tariffs are compatible for distribution connected customers so that the tariff components can be directly summed to provide "bundled" tariffs. Transmission tariffs for transmission-connected customers are nodal (location specific) for loads and generators.

Network access prices have been in place since the introduction of de-regulation into the south-west electricity network in 1996. Initially prices were only set for contestable customers but from July 2001 network prices were established for all customers whether contestable or franchise.

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

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

Customers that were contestable prior to July 2001 were given the option of remaining on the previous tariffs or migrating to the new tariffs. This was facilitated by the retention of a set of transition tariffs. Customers were permitted to choose the tariff that suited them. However the transition tariffs are indexed by cpi plus two percent each year with a view of phasing them out over time as the standard tariffs become cheaper than the transition tariffs. There are in fact only about 30 customers still on transition tariffs and this number is expected to drop considerably over the next few years.

1.1.2 Network Pricing Objectives

The Western Power network businesses earn regulated revenue based on the principles described in the "Network Revenue and Average Price Path Paper" in the Access Arrangement. This revenue entitlement is recovered through a set of tariffs that have been designed to meet a set of high-level objectives described as follows. These objectives are consistent with the Code requirements as described in section 2.1.

The revenue entitlement is recovered from customers in a manner that is:

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

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

- Achieve the target revenue to maintain a viable network business and to deliver efficient network services to all network users,
- Be as cost reflective as is reasonable to reflect the network user's utilisation of the network including use of dedicated assets,
- Promote efficient use of the network through appropriate price signalling,
- Maintain price stability and certainty to enable network users to make informed investment decisions,
- Be as simple and straightforward as is reasonable taking into account other objectives,

- Avoid cross subsidy between different customer groups. From an economic efficiency perspective this requires that the network price be between the "floor" price, which is the incremental cost of service, and a "ceiling" price represented by the stand-alone cost of service.

1.1.3 Pricing Principles

The Western Power network businesses have adopted the following principles that are designed to meet the pricing objectives set out in the previous section.

1. Network prices are to be designed to recover the revenue entitlement while meeting any side constraints to prevent price shock to customers.
2. The prices will be based on a well-defined and transparent methodology.
3. The prices will be based on analysis of the cost of service provision that includes:
    a. Definition of the classes of service provided,
    b. Allocation of fixed and variable network costs to service classes, and
    c. Price setting to recover the fixed and variable costs.
4. Prices will signal the economic cost of service provision in that they will:
    a. Avoid cross subsidies between classes of service, and
    b. Avoid cross subsidies within classes of service.
5. Provided that economic costs are covered, prices will be responsive to customer requirements in order to
    a. Avoid economic bypass, and
    b. Allow for negotiation where provided within the Code.
6. Provide economic signals to encourage efficient use of the network.
7. Network prices for customers with annual energy demand below 1 MVA are uniform across the SWIN (consistent with the Code) while meeting the pricing principles described above, as far as is practical.

2 Overview of Price Structures

This section provides an overview of the network prices that apply to the south-west interconnected transmission and distribution network. The derivation of cost of service and prices is described later in this document.
There are 13 individual network tariffs. The tariffs are structured to meet the requirements of the Electricity Code and to be consistent with the customer metering information available. There are approximated 2000 customers with time based demand and energy metering. A further 16,000 customers have time of use energy metering and the remaining 800,000 customers have any time energy only metering.

The categories of tariffs are:

Distribution-connected customers:

1. Unmetered supplies,
2. Street lights
3. Energy only small,
4. Time of use small,
5. Energy only large,
6. Time of use large,
7. Low voltage (LV) metered demand,
8. High voltage (HV) metered demand,
9. HV Contract maximum demand (HV CMD),
10. LV Contract maximum demand (LV CMD),
11. Distribution connected generation tariffs.

Transmission-connected customers:

1. Transmission nodal tariff (loads),
2. Transmission nodal tariff (generators).

There remains also a set of transition tariffs that are essentially a legacy from the late 1990's that still apply to a small number of customers. These tariffs are only available to customers who were contestable prior to 2000 and who have remained on those tariffs from that time. They are being indexed annually at cpi plus 2% with the purpose of phasing out the tariffs altogether as soon as possible. Their derivation will not be described in this paper because of the low, and declining, number of customers utilising these tariffs and the full intention of phasing out these tariffs in the next few years. These transition tariffs are not available for new customers.

The Code requires uniform network tariffs for all customers with annual energy demand below 1 MVA, which equates to all but 500 within the SWIN. Customers with energy demand below 1MVA will exhibit the full range of energy consumption patterns. It is therefore clear that any tariff structure will not be totally cost reflective. However the assumptions that are made in allocating customers to particular load groups and in deriving the cost of service to those customer groups, and the consequent prices, are all considered reasonable. Through the process described in this paper the tariff settings are derived through as rigorous a process as is possible taking into account the information available and the requirements of the Code.
A basic principle is that there be no cross subsidies between customer groups. For example residential customers should not subsidise small business customers. This issue is addressed by ensuring that the costs allocated to customer groups at the cost of service analysis stage, are recovered by the prices that apply to that customer group.
A significant principle in deriving prices from the cost of service analysis is to set fixed charges to recover the fixed costs and variable charges to recover the variable costs. The allocation of costs to fixed and variable components is subjective to some degree but setting

of tariff components using this principle is the primary strategy to prevent cross subsidies within customer groups. For example, setting the variable component too high and the fixed component too low would result in high consumption customers subsidising low consumption customers.
In the case of transmission all costs have been allocated to customer groups on the basis of demand. Where distribution-connected customers only have energy metering, transmission costs are allocated assuming a load factor for the customer group. The outcome of this decision is that all transmission price components are variable – either based on $ per kVA/kW or cents per kWh.

2.1.1 Distribution-connected customers:

This section provides an overview of the tariff structures and a brief description of each tariff.

It is worth noting that where a fixed charge is indicated, the transmission component is zero for all tariffs.

1. Un-metered supplies

This tariff applies to customers that are not metered at the connection point and include such customer types as telephone boxes, traffic lights and railway crossings.

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

The un-metered customer tariff structure for distribution is based on:

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

The un-metered customer tariff structure for transmission is based on:

- A charge per kWh for calculated energy consumption.

2. Street lights

Street-lights are in the same category as un-metered supplies in that there is no metering and the energy consumption must be estimated. As such the network access tariff structure for both transmission and distribution mirrors the un-metered supply tariff in that:

The streetlight tariff structure for distribution is based on:

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

The streetlight tariff structure for transmission is based on:

- A charge per kWh for calculated energy consumption.

In addition there is a charge to reflect the capital and operating costs of the street light asset itself. The assets are owned by the network business and the revenue is included in the regulated return. The tariff structure for the street light asset is simply a fixed charge per light based on the type and rating of the light.

3. Energy only small

This tariff caters for residential customers with anytime energy only metering. There are approximately 700,000 customers that fit into this category.

The energy small tariff structure for distribution is based on:

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

The energy small tariff structure for transmission is based on:

- A charge per kWh for calculated energy consumption.

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

4. Time of use small

This tariff caters for residential customers and small business customers with energy consumption below 50 MWhs per annum that have time of use energy metering. There are approximately 20,000 customers that fit into this category.

The time of use small customer tariff structure for distribution is based on:

- A fixed charge per customer,
- A charge per kWh for metered on peak energy consumption, and
- A charge per kWh for metered off peak energy consumption.

The time of use small customer tariff structure for transmission is based on:

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

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

5. Energy only large

This tariff caters for small business customers with anytime energy only metering. There are approximately 80,000 customers that fit into this category.

The energy only large customer tariff structure for distribution is based on:

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

The energy only large customer tariff structure for transmission is based on:

- A charge per kWh for metered energy consumption.

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

6. Time of use large

This tariff caters for business customers with energy consumption above 50 MWhs per annum that have time of use energy metering. There are approximately 16,000 customers that fit into this category.

The time of use large customer tariff structure for distribution is based on:

- A fixed charge per customer,
- A charge per kWh for metered on peak energy consumption, and
- A charge per kWh for metered off peak energy consumption.

The time of use large customer tariff structure for transmission is based on:

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

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

7. Low voltage (LV) metered demand

This tariff caters for business customers that are connected to the distribution network at low voltage, have a maximum any time demand of 1,500 kVA, and have time based energy and demand metering.

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

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

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

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

8. High voltage (HV) metered demand

This tariff caters for business customers that are connected to the distribution network at high voltage, have a maximum any time demand of 1,500 kVA, and have time based energy and demand metering.

The tariff structure and incentives are identical to the structure for the low voltage metered demand tariff.

9. LV Contract maximum demand (LV CMD)

This tariff caters for business customers that are connected to the distribution network at low voltage, have an any time demand in excess of 1,000 kVA, and have time-based energy and demand metering.

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

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

There are also separate charges for administration and metering.

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

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

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

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

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

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

10. HV Contract maximum demand (HV CMD)

This tariff caters for business customers that are connected to the distribution network at high voltage, have an any time demand in excess of 1,000 kVA, and have time based energy and demand metering.

The tariff structure and incentives are identical to the structure for the low voltage CMD tariff.

11. Distribution connected generation tariffs.

This is the only tariff that does not facilitate bundling of the transmission and distribution components. The transmission and distribution components must be determined individually.

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

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

The distribution charge is based on the zonal CMD demand length price. There is no demand only charge. As such the distribution charge for generators with demand less than 1000 kVA is zero. There is also a separate metering charge.

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

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

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

Transmission-connected customers:

1. Transmission nodal tariff (loads)

This tariff caters for business customers that are connected to the transmission network at either high or low voltage and have time-based energy and demand metering.

The tariff is based on the zone substation to which the customer is connected. The customer connected at high voltage will pay the "use of system" and "common service" charge and the customer connected at low voltage will also pay the "connection" charge. There is also a separate metering charge. All prices are in $ per kW.

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

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

2. Transmission nodal tariff (generators).

This tariff applies to generators that are connected to the transmission network at either high or low voltage and have time-based energy and demand metering. In conjunction with the distribution generation tariff, it also applies to distribution-connected generators.

The tariff is based on the zone substation to which the generator is connected. The generator connected at high voltage will pay the entry point "use of system" only charge and the generator connected at low voltage will also pay the "connection" charge. There is also a separate metering charge. All prices are in $ per kW.

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

3 Methodology for Establishing Network Prices

General

Network prices aim to reasonably reflect the cost of providing the network service to customers. Therefore the first step in developing network access prices is to model the cost of service for customers. The cost of service cannot be derived at an individual customer level and so customers are categorised into a number of groups with similar costs.

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

Demand is the best measurement of capacity but as the vast majority of customers have energy only metering that does not record demand, energy is used as a proxy for demand.

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

It should be recognised that the determination of the cost of service for customers and respective prices is not a completely definitive process. Some assumptions are required, and by categorising customers into a small number of customer groups or classes and with the limitations on the metering information available minor non-deterministic error may be introduced which can not be avoided or quantified. However, this error should not be significant and there is considerable historical precedence in deriving the network cost of service that supports the approach.

Process to Determine Cost of Service

There are two basic stages in determining the cost of service for customers:

- Determination of the forecast annual revenue requirement for the network business; and

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

Determination of the forecast annual revenue requirement for the network business is outside the scope of this paper and is assumed to be determined.

That revenue requirement must then be allocated to asset classes and the use of the assets allocated to customers.

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

Transmission connected:

- Transmission Generation
- Transmission Loads

Distribution connected:

- High Voltage >1MVA maximum demand
- High Voltage <1MVA maximum demand
- Low Voltage >1MVA maximum demand
- General Business Large (300-1000kVA maximum demand)
- General Business Medium (100-300kVA maximum demand)
- General Business Small (15-100kVA maximum demand)
- Small Business (<15kVA maximum demand)
- Residential
- Streetlights
- Unmetered Supplies

Process to Determine Network Prices

Network access prices are derived from the cost of service determination. The cost of service is determined for the customer groups listed in the previous section. The network tariffs do not directly relate to the customer groups. This is because a number of the customer groups are based on derived customer demands whereas the network tariffs are based on the customer and metering data that is actually available.

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

Cost Allocations - General

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

4 Transmission Cost of Service

Classes of Service

Generally, the Target Revenue is recovered from transmission charges for the following classes of transmission service:

- Connection Services – for the use of assets which are fully dedicated to connecting customers to the shared transmission network,

- Transmission network Use Of System (TUOS) Services – for the use of a portion of the shared transmission network allocated on a locational user pays basis,

- Common Services - for the use of a portion of the shared transmission network that benefits all transmission customers and is not allocated on a locational basis,

- Other Network Services – for the use of other assets such supervisory control and communications facilities which are used in managing the transmission network.

Cost of Service

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

4.1.1 Transmission Assets

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

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

- Connection Assets: those assets at the point of physical interconnection with the transmission networks which are dedicated to a User - that is, at substations including transformers and switchgear, but excluding the incoming line switchgear. Connection assets for generators are referred to as entry assets and for loads they are called exit assets.
- Shared Network Assets: all other transmission assets, which are shared to some extent by network Users.
- Other or Ancillary Assets: network assets performing an Ancillary Services function comprise:

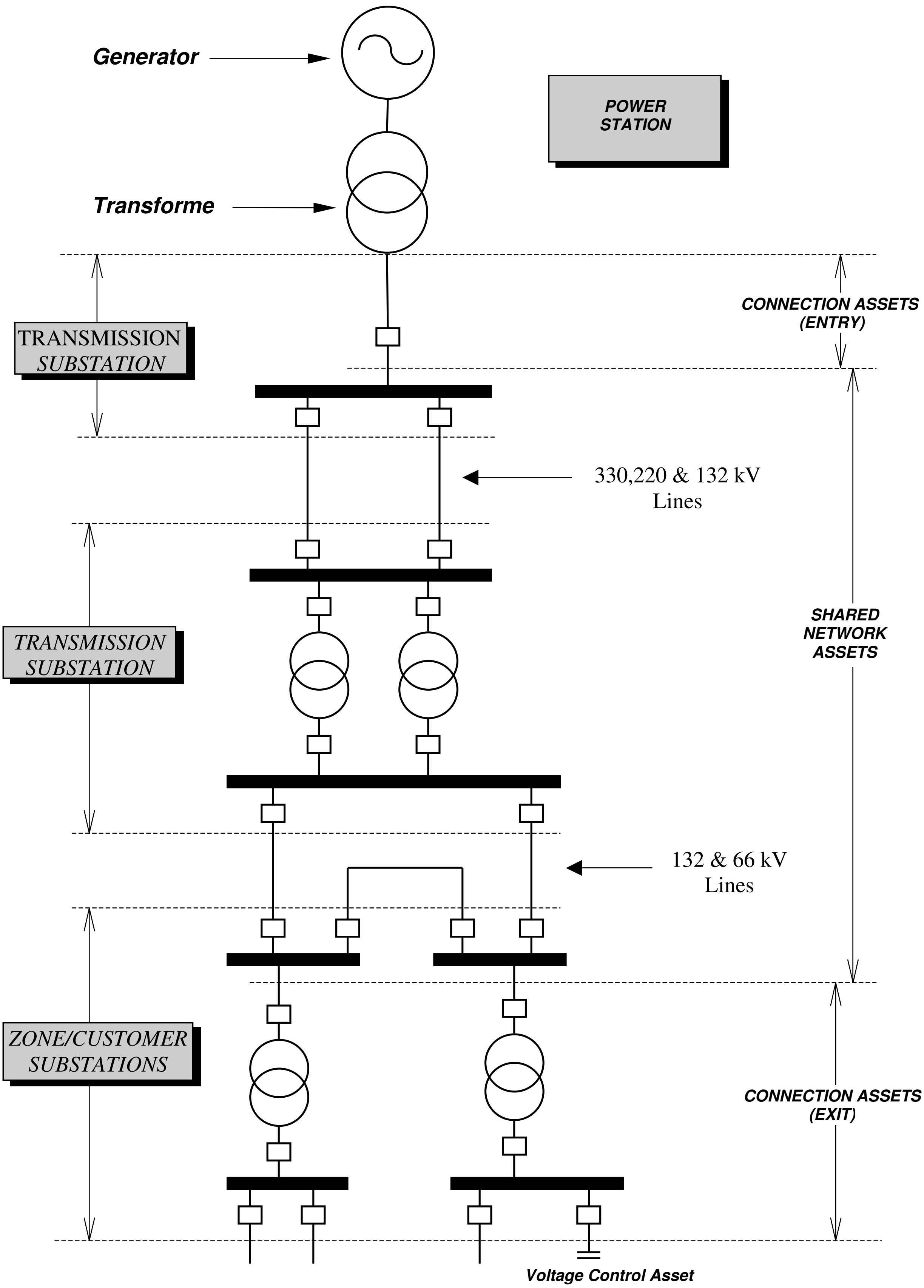
    - those providing a Control System Service, for example, system control centres, supervisory control and communications facilities.

    - those providing a Voltage Control Service in the networks, for example, a proportion of the costs of capacitor and reactor banks in substations.

The following diagram shows in simplified form the principal elements of the transmission networks and the categorisation of the assets as described above.

Transmission Network Assets

Indicative Diagram



4.1.2 Asset Valuation

A valuation of transmission assets is undertaken using the Optimised Deprival Value methodology. See the Physical Assets Valuation report for details, however generally the valuation approach is as described below.

Optimised Deprival Value Method

The Optimised Deprival Value (ODV) of an asset is the depreciated value of the lower of the optimised replacement cost of the asset and the economic replacement value of the asset, where:

(a) the optimised replacement cost of the asset is the cost of meeting the current (and projected future) supply needs with the most technically efficient design and configuration of the asset based on the existing system configuration; and

(b) the economic replacement value of an asset is the minimum cost of replacing the asset with a more economic alternative which still achieves the same result.

The ODV of the network is determined as follows:

(1) the modern equivalent for each asset is established in a building block format.

(2) any overbuild or sub-optimal configuration of the existing system is identified, taking into account load forecast, system security, reliability and the overall system integrity;

(3) the replacement cost of the optimal asset is determined, based on the modern equivalent asset;

(4) the optimised replacement cost and the economic replacement value of each asset are established;

(5) the lower of the optimised replacement cost and economic value of each asset is summated to form the gross ODV of all assets

(6) the lower of the depreciated optimised replacement cost and economic value of each asset is summated to form the ODV of all assets

4.1.3 Valuation of Individual Branches and Nodes

For Transmission Pricing, valuation data is required for every individual branch and node on the network. Every Branch and Node consists of many individual asset valuation building blocks which are all individually assessed.

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

Substation Site Establishment costs are allocated equally to all substation circuits.

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

Cost Pools

Assets are divided into cost pools which relate to the different components of the network access prices. The cost pools are:

- Connection Services Cost Pool:
  which is further allocated to the following cost pools,
  - Connection Services for Exit Points Cost Pool, and
  - Connection Services for Entry Points Cost Pool.

- Shared Network Services Cost Pool:
  which is further allocated to the following cost pools,
  - Use Of System for Loads Cost Pool,
  - Use Of System for Generators Cost Pool, and
  - Common Service for Loads Cost Pool.

- Control System Services Cost Pool:
  which is further allocated to the following cost pools,
  - Control System Services for Loads Cost Pool,
  - Control System Services for Generators Cost Pool.

4.1.4 Connection Services for Exit Points Cost Pool

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

4.1.5 Connection Services for Entry Points Cost Pool

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

4.1.6 Use of System for Loads Cost Pool

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

4.1.7 Use of System for Generators Cost Pool

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

4.1.8 Common Service for Loads Cost Pool

The Common Service for Loads Cost Pool includes:

- 30% of the total Shared Network Services Cost Pool.

- Shared Voltage Control Assets – two thirds of the value of voltage control assets at Entry and Exit points (since the function of voltage control equipment is partly location specific and partly system related) and the value of all of voltage control assets at transmission substations. NB The remaining one-third of the value of the voltage control equipment at Entry and Exit points is included in the Connection Services Cost Pool (see above).

- Generation Support Charge - is an annual pass through cost determined by the market operator for running some small generation units out of merit in order to minimise excessive transmission losses and aid in system stability.
- Regulation Service to Loads - is an annual pass through cost determined by the market operator required to control frequency variations caused by load fluctuations (see Western Power Networks, *'Price Publication – Part E'*).
- Adjustments for any under or over recovery in revenue from previous financial years, or any under recovery expected due to price caps in the current year.

4.1.9 Control System Service for Loads Cost Pool

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

4.1.10 Control System Service for Generators Cost Pool

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

Allocation of Target Revenue to Cost Pools

Generally, the allocation of the required revenue from each cost pool is in proportion to the GODV of the assets in each cost pool.

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

Consequently:

Cost Pool Revenue = RR * GODV (Cost Pool)

where:

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

$AARR_{network}$ = AARR excluding Annual Revenue Requirement for Control System Services.

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

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

5 Transmission Price Determination

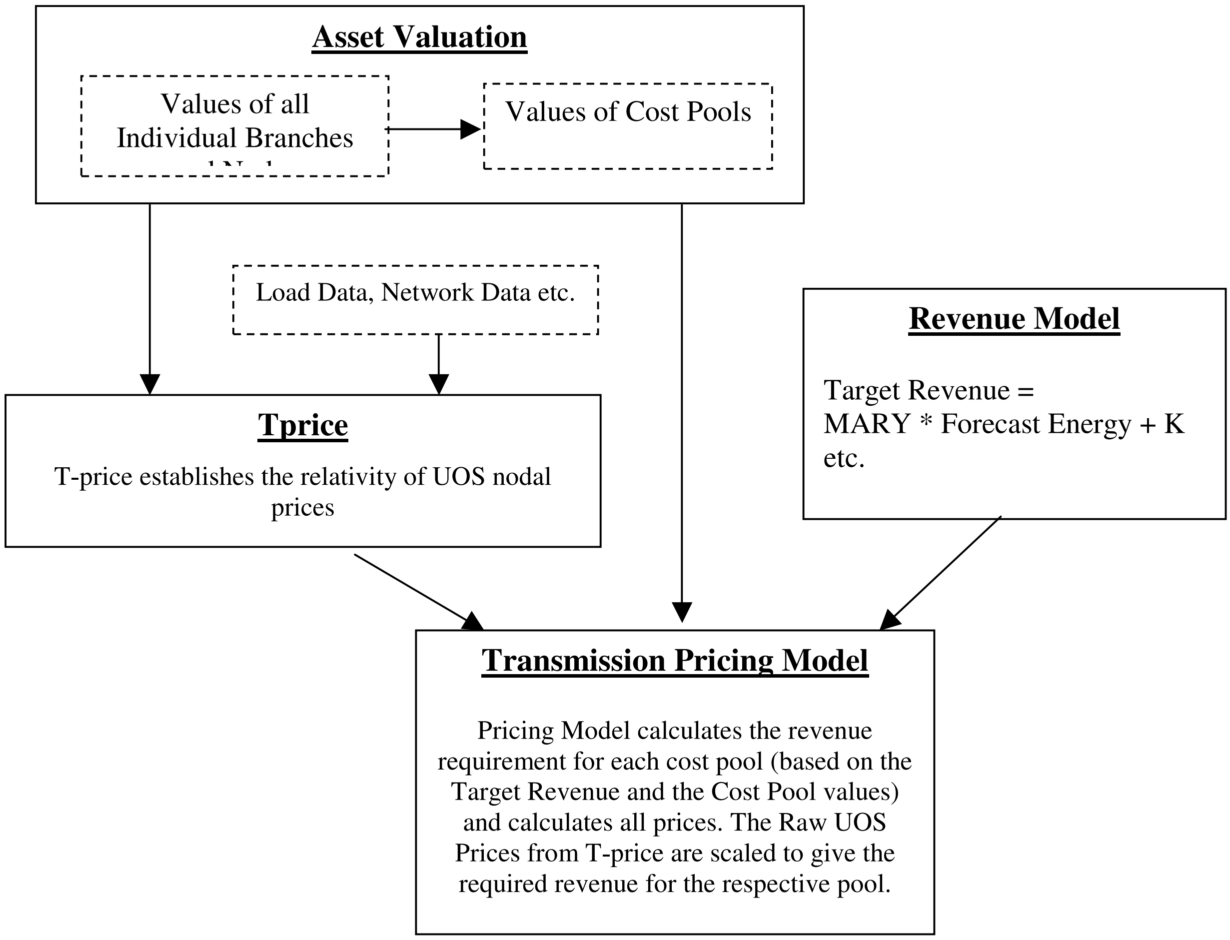
This section describes the methodology used to calculate initial transmission access prices at the commencement of the Access Arrangement and the annual review of these prices.

Transmission access prices for Exit and Entry points are fixed and are generally expressed as $/kw/annum. Generally, transmission prices are derived by dividing the cost pool, either in its entirety or at a zone substation level, by the assigned maximum demand applying to those assets. However, the details of some parts of the process are complex.

Generally

WPC uses T-price to establish the relativity of Use Of System prices for each exit and entry point. T-price is a modelling tool to allocate network costs to each node using Cost Reflective Network Pricing. T-price has been given interim approval by NECA for this purpose and is used by all transmission businesses across Australia.

Once Transmisison assets are valued, T-price is used to establish the relativity of UOS prices, and the Transmission Pricing Model is used: 1) to calculate the annual revenue requirements for all respective cost pools (based on valuation data and the rate of return required), 2) to scale the raw T-price UOS prices to give the required Use Of System cost pool revenues, 3) to calculate the Connection, Common Service, and Control System Services prices by dividing the respective cost pool by the respective forecast CMDs (for the coming year).



Initial Prices

Initial prices are calculated as described below and reviewed annually.

5.1.1 Connection Price

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

Connection charges for loads connected directly to the transmission network at 66kV or above are not published but are determined subject to the specific connection arrangements. These connection charges are individually calculated to reflect the actual connection assets that apply to that customer. The amount of the charge is based on achieving a regulated return on all relevant assets and an allocation of the transmission network operating costs.

5.1.2 Use of System Prices

Consistent with the NEC, the proportion of the Target Revenue which is for Transmission UOS is allocated to each and every connection point using a Cost Reflective Network Pricing method (CRNP). CRNP assigns a proportion of shared network costs to individual customer connection points.

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

UOS – Exit Points

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

UOS – Entry Points

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

5.1.3 Common Service Price for Loads

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

5.1.4 Control System Service Price

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

CSS for Loads

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

CSS for Generators

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

T-price

T-price requires significant work to establish all of the inputs and to run the model. However, in summary:

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

Cost Reflective Network Pricing

5.1.5 General

The Cost Reflective Network Pricing cost allocation method allocates the revenue requirement to all network elements, based on their gross (ie undepreciated) ODV, then determines the use made of each network element by each connection point during the survey period.

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

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

(ii) determining the network load and generation pattern;

(iii) performing a load-flow to calculate the MVA loading on network elements;

(iv) determining the allocation of generation to loads;

(v) determining the utilisation of each asset on the network by each connection point;

(vi) allocating the revenue requirement of individual network elements to each user based on the assessed usage share; and

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

5.1.6 Allocation of Generation to Load

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

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

5.1.7 Operating Conditions for Cost Allocation

The choice of operating conditions is important in developing prices using the CRNP methodology. The use made of the network by particular loads and generators will vary depending on the load and generation conditions on the network at the time. The NEC sets out the principles to apply in determining the sample of operating conditions considered.

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

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

- Load and generation conditions shall be actual operating conditions from the previous 12 months; and

Operating conditions shall include data for every node for every half hour where system peak demand is greater than an amount such that data from 10 individual summer days and 10 individual winter days are included.

Annual Price Review

As described in the appendix 7 of the Access Arrangement, the Target Revenue is reviewed annually and adjusted if necessary for under or over recovery or revised energy forecasts etc. Together with changes to customer CMDs and DSOCs (including zone substation maximum demands) it is consequently necessary to adjust prices annually also.

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

Transmission Use of System prices can be volatile due to matters beyond the control of any one customer. In order to minimise this volatility and reduce the commercial uncertainty for customers, prices are consequently subject to an annual side constraint of plus or minus CPI + 2%.

Allocation of Transmission Costs to Distribution Connected Customers

The Transmission cost of service is developed for all customer groups. T there are customers connected to both the transmission and distribution networks, both of which use the transmission network.

Charges are determined for each direct connected Transmission customer based on respective Contract Maximum Demands (CMDs). The revenues from these customers are then deducted from the Transmission Business' target revenue for that substation to give a net revenue amount to be recovered from customers connected to that substation via the distribution network.

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

Application of Transmission Prices

Application of prices can be complex and the information provided here is for a guide only.

5.1.8 Exit Points

The access charge in respect of each transmission exit **connection** during a **month** is determined by applying the following formula:

Monthly Access Charge (in $) =

Connection Charge / 12

\+ **(Use of System Price + Common Service Price) * Maximum Demand / 12**

\+ **Metering Charge / 12**

\+ **Excess Network Usage Charge** (if applicable)

where:

Connection Charge (in $/annum) is individually determined for **connections** to the transmission network at 66kV or above. For on-site loads associated with generators connected to either the transmission network at less than 66kV or the distribution network the **Connection Charge** (in $/annum) = **(Connection Price + Control System Services Price**$_{\textbf{Loads}}$) * **Maximum Demand**

Connection Price (in $/kW/annum) is the Connection Price for Exit Points in the Transmission Nodal Prices in the **Price Schedule**,

Control System Services Price$_{\textbf{Loads}}$ (in $/kW/annum) is the Control System Services Price for loads in the **Price Schedule**,

Use of System Price (in $/kW/annum) is the Use of System Price for Exit Points in the Transmission Nodal Prices in the **Price Schedule**,

Common Service Price (in $/kW/annum) is the Common Service Price for Exit Points in the Transmission Nodal Prices in the **Price Schedule**,

Maximum Demand (in kW) is the highest **Contract Maximum Demand** in respect of the **connection** for the **month**,

Metering Charge (in $/annum),

Excess Network Usage Charge (in $).

5.1.9 Entry Points

The access charge in respect of each transmission entry **connection** during a **month** is determined by applying the following formula:

Monthly Access Charge (in $) =

Connection Charge / 12

\+ **Use of System Price * Declared Sent Out Capacity / 12**

\+ **Control System Services Price$_{\textbf{Generators}}$ * Maximum Output / 12** (if applicable)

\+ **Metering Charge / 12**

\+ **Distribution Access Charge** (if applicable)

\+ **Excess Network Usage Charge** (if applicable)

where:

Connection Charge (in $/annum) is the Total Connection Charge in the Transmission Nodal Prices for Entry Points to the transmission network at 66 kV or above as individually determined by **Networks**. For generators connected to either the transmission network at less than 66 kV or the distribution network the **Connection Charge** (in $/annum) = **Connection Price** * **Declared Sent Out Capacity**

Connection Price (in $/kW/annum) is the Connection Price for Entry Points in the Transmission Nodal Prices in the **Price Schedule**,

Declared Sent Out Capacity (in kW) is the highest **Declared Sent Out Capacity** in respect of the **connection** for the **month**,

Use of System Price (in $/kW/annum) is the Use of System Price for Entry Points in the Transmission Nodal Prices in the **Price Schedule**,

Control System Services Price$_{\textbf{Generators}}$ (in $/kW/annum) is only applicable to generators connected to either the transmission network at less than 66 kV or the distribution network, and is the Control System Services Price for generators in the **Price**

Schedule. (For other connections the Control System Services Charge is included in the Total Connection Charge.)

Maximum Output (in kW) is the highest aggregate maximum net output of the generating units connected to the electricity network at the **connection** for the **month**,

Distribution Access Charge (in $) is zero for a **connection** connected directly to the **electricity transmission network**.

Metering Charge (in $/annum),

Excess Network Usage Charge (in $).

5.1.10 Combined Entry and Exit Points

Where a **connection** is used as both an Exit and Entry point the access charges are the higher of the Exit Point Charges and Entry Point Charges, which are calculated separately for all loads and generation at the **connection.**

6 Transmission Prices for Distribution-Connected Customers

Transmission prices are derived for distribution-connected customers because they use the transmission system in the same manner as transmission-connected customers. The revenue that is to be recovered from distribution-connected customers is calculated by taking the full forecast transmission tariff revenue entitlement, and subtracting the transmission revenue forecast to be recovered from all transmission-connected loads and generators.

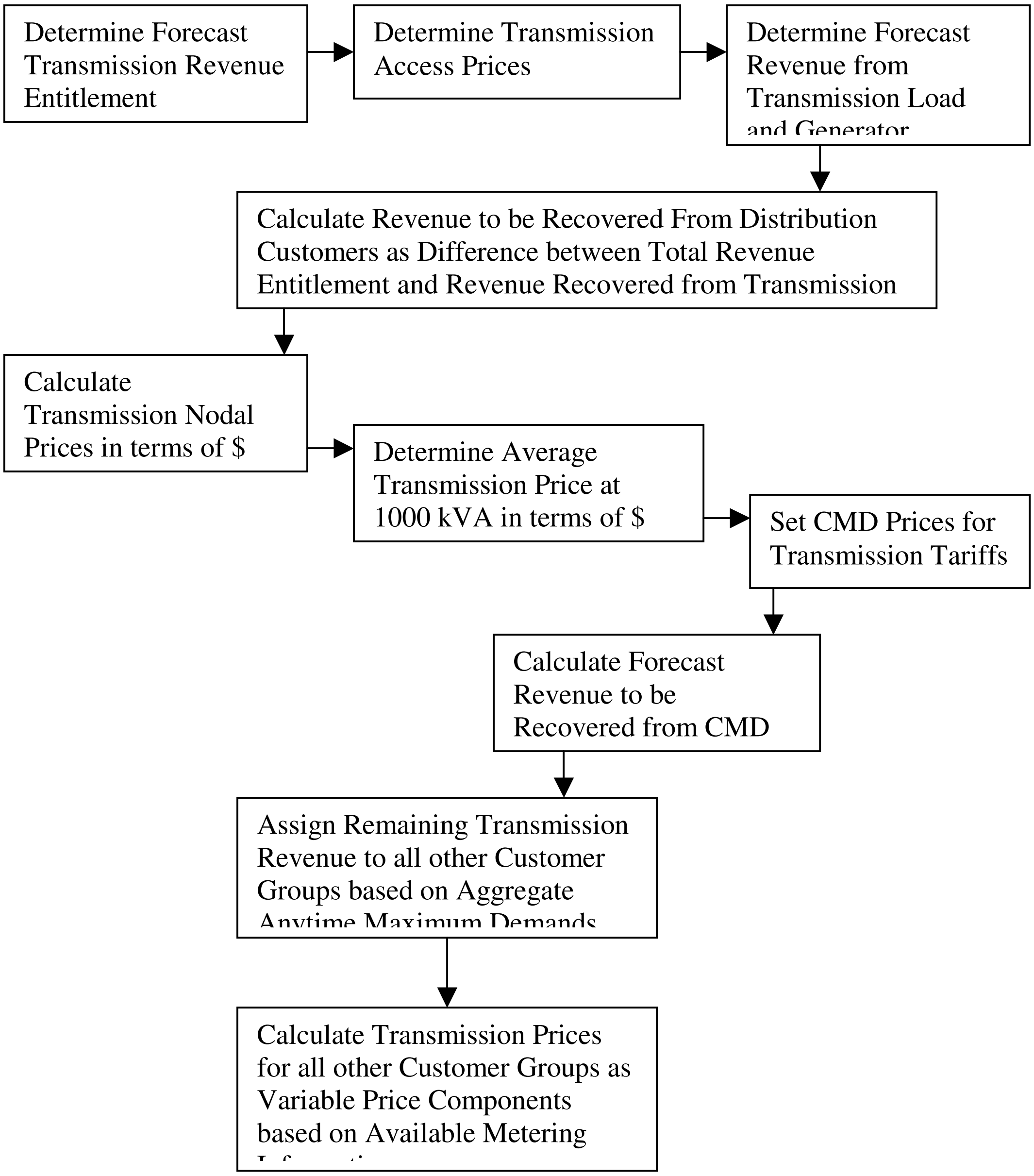
A number of processes then take place to determine transmission prices that match the structure of distribution prices so that a full suite of bundled tariffs can be produced.

As previously noted, distribution customers fall into the following tariff groups for which transmission prices must be derived.

1. HV Contract maximum demand (HV CMD),
2. LV Contract maximum demand (LV CMD),
3. Low voltage (LV) metered demand,
4. High voltage (HV) metered demand,
5. Energy only large,
6. Time of use large,
7. Energy only small,
8. Time of use small,
9. Unmetered supplies,
10. Street lights
11. Distribution connected generation tariffs.

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

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



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

Calculate the Forecast Revenue to be Recovered from Distribution-Connected Customers

It is assumed at this stage that the forecast transmission revenue entitlement has been determined and transmission prices set. By applying those prices to the forecast transmission-connected customer data, the revenue to be recovered from transmission load and generation customers can be forecast. The residual is the revenue that must be recovered from distribution-connected customers.

Calculate Transmission Nodal Prices in Terms of $ per kVA

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

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

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

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

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

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

Determine Average Transmission Price at 1,000 kVA

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

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

The anytime maximum demands are not metered for the vast majority of customers with demands below 1000 kVA. The energy consumption is metered and the anytime maximum demands are estimated by applying load factors based on “Industry Codes”. The industry codes and associated load factors were developed using sample data for actual representative customer types.

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

$$RP_{Below\ 1000} = RP_{Total} - RP_{Over\ 7000} - RP_{1000\ to\ 7000}$$

where,

$RP_{Below\ 1000}$ = revenue to be recovered from customers with demands below 1,000 kVA

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

$RP_{Over\ 7000}$ = revenue to be recovered from customers with demands greater than 7,000 kVA

$RP_{1000\ to\ 7000}$ = revenue to be recovered from customers with demands between 1,000 and 7,000 kVA

This equation has unknowns in several terms at this stage. The revenue to be recovered from customers with demands greater than 7,000 kVA is known because it is equal to the forecast demands of those customers multiplied by the nodal price for each customer. None of the other terms is readily determined.

To facilitate the solving of this equation the pricing structure of customers with demands between 1,000 and 7,000 kVA must be determined. To facilitate the bundling of transmission and distribution network prices the transmission price structure must be consistent with the distribution price structure. For these customers this means the prices will be in “rate block” structure and take the form:

$$\text{Customer Charge}_{1000\ to\ 7000} = (\text{Price}_{At\ 1000} * 1000\ \text{kVA}) + (\text{Price}_{1000\ to\ 7000} *(\text{CMD}_{Customer} - 1000\ \text{kVA}))$$

where,

$\text{Customer Charge}_{1000\ to\ 7000}$ = the use of system charge for a customer with CMD between 1000 and 7000 kVA

$\text{Price}_{At\ 1000}$ = the average use of system price for all customers with CMD below 1000 kVA

$\text{Price}_{1000\ to\ 7000}$ = the use of system for this customer with CMD between 1000 and 7000 kVA

$\text{CMD}_{Customer}$ = the contract maximum demand for that customer

The $\text{Price}_{1000\ to\ 7000}$ will be different for each zone substation but can be calculated by the formula:

$$\text{Price}_{1000\ to\ 7000} = [(\text{Price}_{At\ 7000} * 7000\ \text{kVA}) - (\text{Price}_{At\ 1000} * 1000\ \text{kVA})]/6000\ \text{kVA}$$

So we now have a formula to calculate the price for each customer with CMD between 1,000 and 7,000 kVA with the unknown being the price at 1000 kVA. We now have a single unknown (Price $_{\text{At }1000}$) that can now be solved in the above equation which now must be expanded as below.

Original Equation:

$$RP_{\text{Below }1000} = RP_{\text{Total}} - RP_{\text{Over }7000} - RP_{1000\text{ to }7000}$$

Expansion of each term:

$RP_{\text{Below }1000}$ = $\sum$ Customer anytime maximum demands multiplied by Price $_{\text{At }1000}$

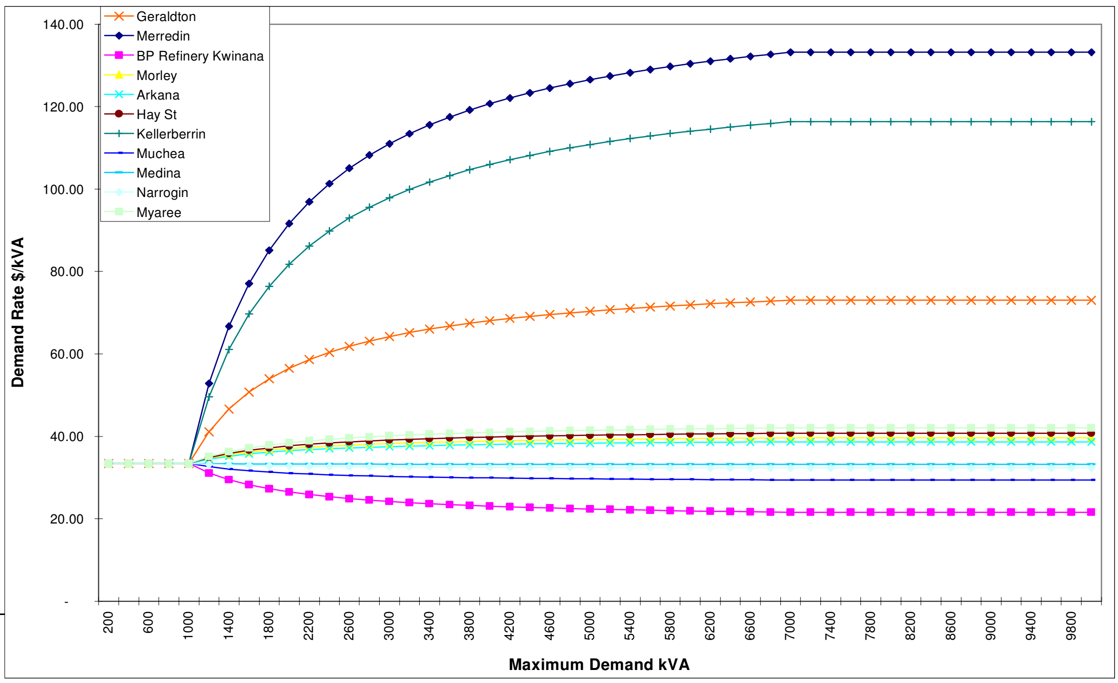
RP_{Total} = Total transmission revenue entitlement allocated to distribution-connected customers

$RP_{\text{Over }7000}$ = $\sum$ Individual demands for customers greater than 7000 kVA anytime maximum demands multiplied by the nodal price at the zone substation to which the customer is connected

$RP_{1000\text{ to }7000}$ = $\sum$ Customer charges for all customers with CMDs between 1000 and 7000 kVA

At this stage of the process we have the average price at and below 1,000 kVA, the nodal price for each zone substation for demands between 1000 and 7000 kVA and the nodal price for demands greater than 1000 kVA. This has set the transmission tariffs for CMD customers.

The rate blocks were developed using the principle of a straight-line transition from the charge at 1000 kVA to the charge at 7000 kVA. When converted back to prices the actual prices at any demand can be mapped and in fact the transition from a flat price below 1000 kVA to a flat price above 7000 kVA is a 1/x curve. The following graph illustrates the price outcomes for the above process. A number of substations have been chosen to represent the range of prices across urban and rural substations



Calculate Transmission Revenue to be Recovered from Customer with Demands Below 1,000 kVA

This has been determined in the previous section in that the revenue is the average price multiplied by the sum of the anytime maximum demands of all customers with demands less than 1000 kVA.

Calculate Transmission Prices for all other Customer Groups

The first step in this process is to allocate the total revenue entitlement for all customers with demands below 1000 kVA to the customer groups within this category. The customer groups are restated for reference.

- General Business Large (300-1000kVA MD)
- General Business Medium (100-300kVA MD)
- General Business Small (15-100kVA MD)
- Small Business (<15kVA MD)
- Residential
- Streetlights
- Unmetered Supplies

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

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

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

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

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

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

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

7 Distribution Cost of Service

The distribution network business, from the perspective of developing network prices, operates along the same principles as the transmission network. That is, the revenue entitlement is determined for the distribution network business, and that revenue is then allocated to asset categories to derive the cost of service for each of the customer groups. The cost of service is based on the relative usage of each asset category by the various customer groups.

To understand the structure of the distribution network cost of service and access prices, it is important to understand the features of the distribution network which are described in the following section.

Description of the Electricity Distribution Network

The following descriptions of the distribution network describe the separate parts of the Western Power networks, the extent of the network and the equipment that makes up the network. This is also intended to satisfy the requirement in the Code to provide a maintained definition of the network.

7.1.1 Definition of Network

The electricity distribution network is defined in the Act as “that part or those parts of the system operating at less than 66 kV and at a nominal frequency of 50 Hz.”

Western Power’s networks include the following principal elements:

- Sub-networks supplied from transmission zone sub-stations operating at voltages of 33 kV, 22 kV, 19.1 kV, 12.7 kV, 11 kV and 6.6 kV. Sub-networks contain multiple feeder circuits.
- The feeder circuits emanating from transmission zone sub-stations operating at a voltages of 33 kV, 22 kV, 19.1 kV, 12.7 kV, 11 kV and 6.6 kV. These are generally interconnectable between other feeders.
- The sub-network supplied from regional power stations connected to the secondary side of the generator step-up/down transformers operating at 33 kV, 22 kV, 19.1 kV, 12.7 kV, 11 kV, 6.6 kV and 415 V.
- Distribution transformers to supply power at 415 V.
- 415 V low voltage power lines.
- Protective devices.

There are about 63,000 km of high voltage distribution mains and 16,000 km of low voltage distribution mains installed in Western Power’s interconnected and regional systems. The total installed transformer capacity is 4,350 MVA.

The distribution lines are composed of aluminium and copper overhead conductors and underground cables of both aluminium and copper construction. There are also high tensile steel reinforced overhead conductors and earth wires.

The majority of the network is supplied by three-phase power with the remainder consisting of single phase and two-phase lines. The single-phase system is generally located in areas outside the Perth metropolitan area and major country centres.

7.1.2 Description of South West Interconnected Network

The South West Interconnected Network extends from Kalbarri in the North, down the West Coast of Western Australia and along the Southern Coast to Bremer Bay and eastwards to the

Eastern Goldfields, as shown in Figure 6. There are approximately 130 transmission zone sub-stations in the South West Interconnected Network. Some of these are either wholly or partly privately owned.

The 6.6 kV and 11 kV distribution networks are in the older areas of the Perth metropolitan area. The 22 kV system supplies the remainder of the metropolitan area. The rural SWIN network is supplied by further 22 kV or 33 kV networks with many single-phase extensions.

Protective devices are located on feeders emanating from zone sub-stations. These devices provide a measure of protection for the distribution network. Reclosers and sectionalisers are located on the SWIN.

Typical network configurations for CBD, Urban, Mining and Rural connections are shown in Figures 1, 2, 3 and 4.

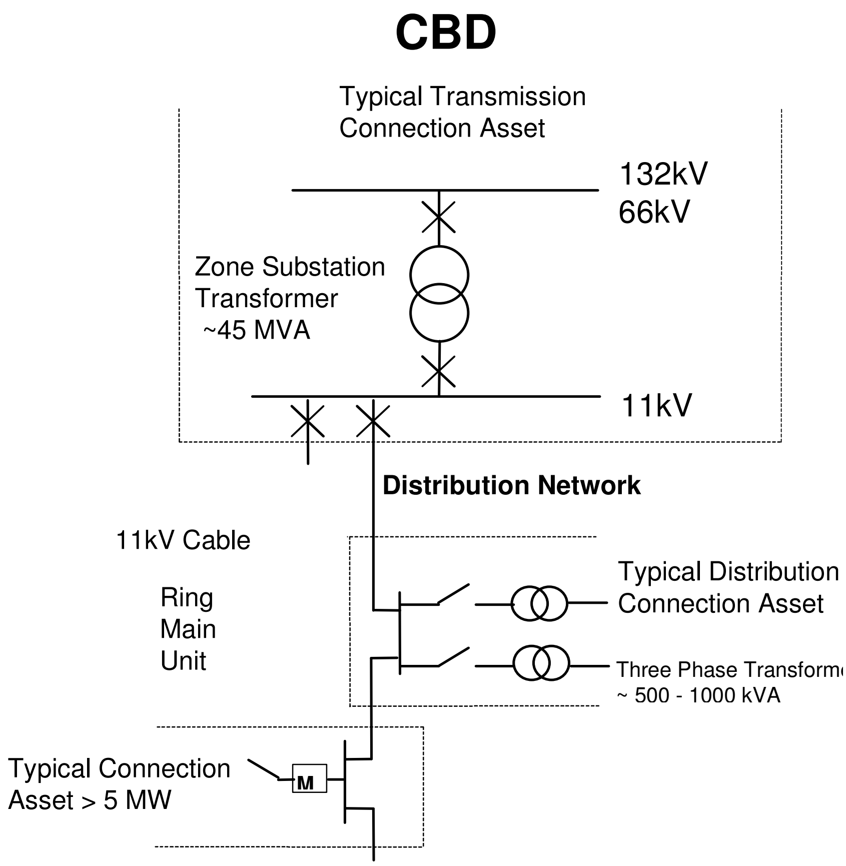


Figure 1 Typical Network Configuration - CBD

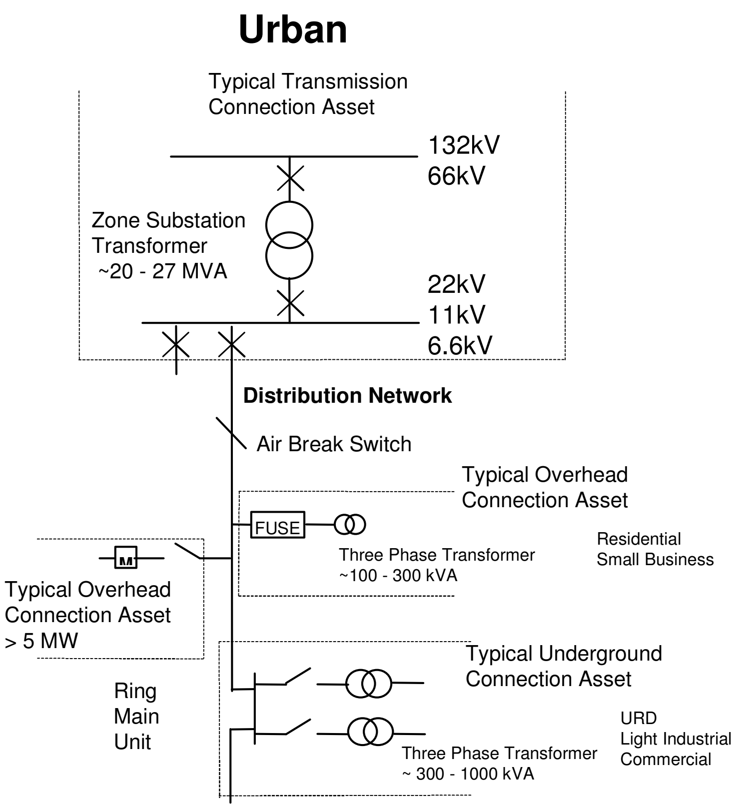


Figure 2 Typical Network Configuration - Urban

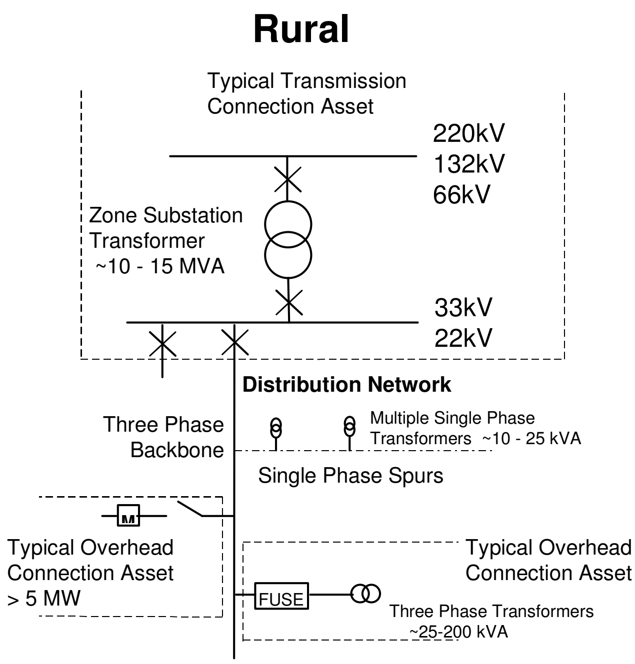


Figure 3 Typical Network Configuration - Rural

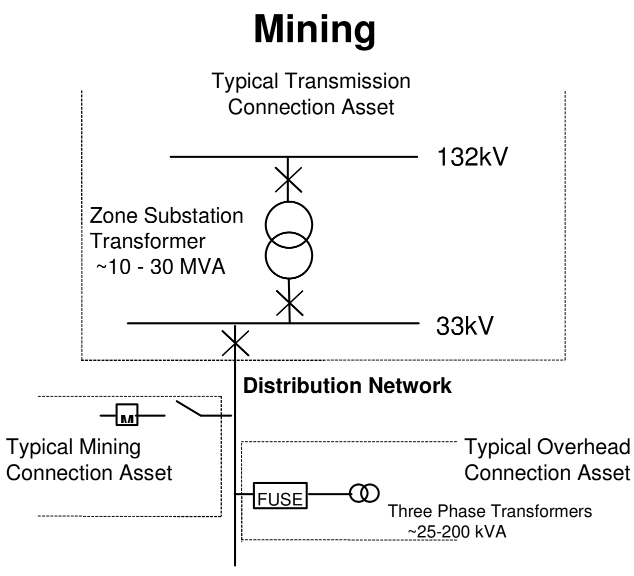


Figure 4 Typical Network Configuration - Mining

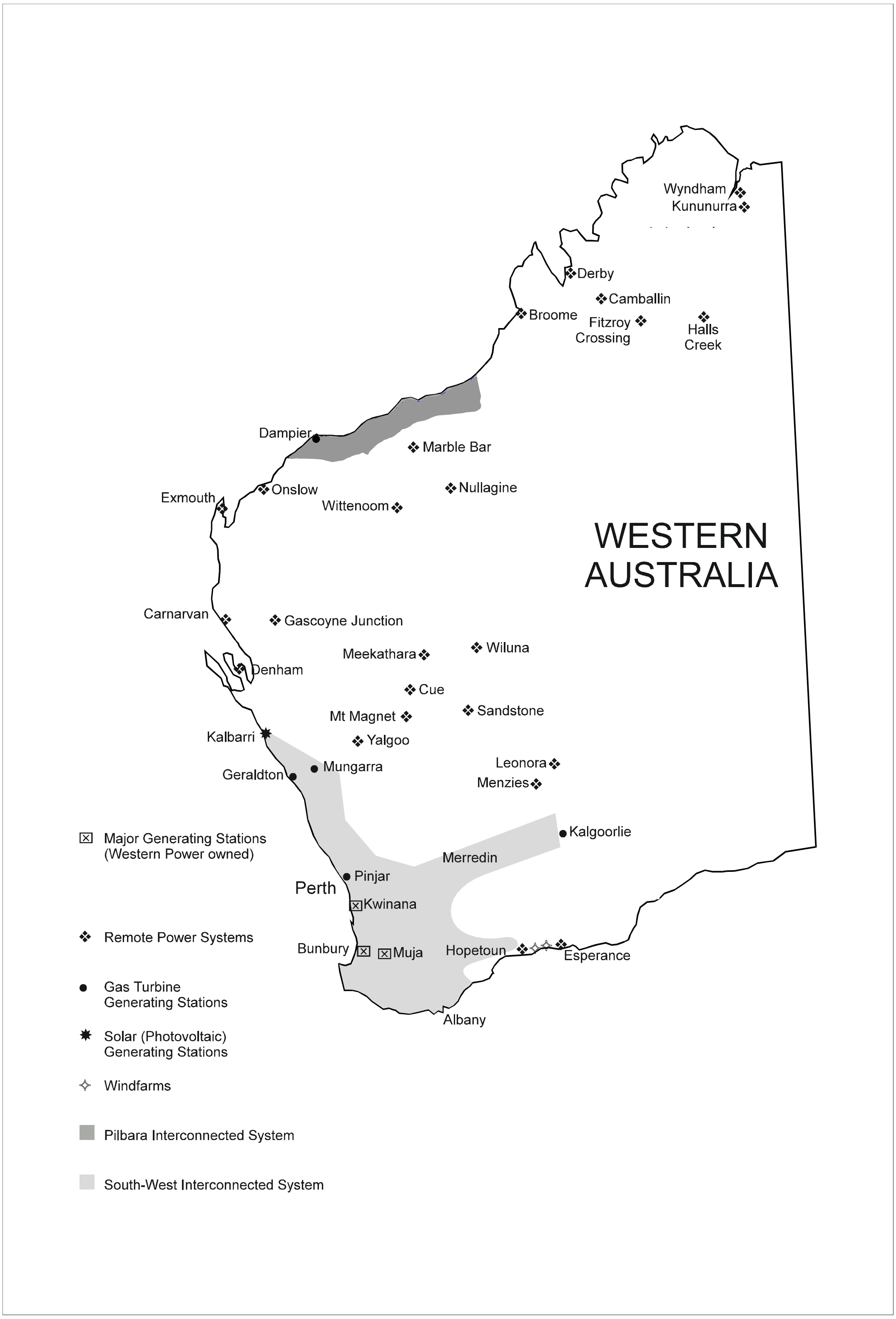


Figure 6 Western Power's Networks

Definition of Locational Zones

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

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

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

7.1.3 CBD Locational Zone

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

7.1.4 Urban Locational Zone

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

7.1.5 Rural Locational Zone

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

7.1.6 Mixed Locational Zone

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

7.1.7 Mining Locational Zone

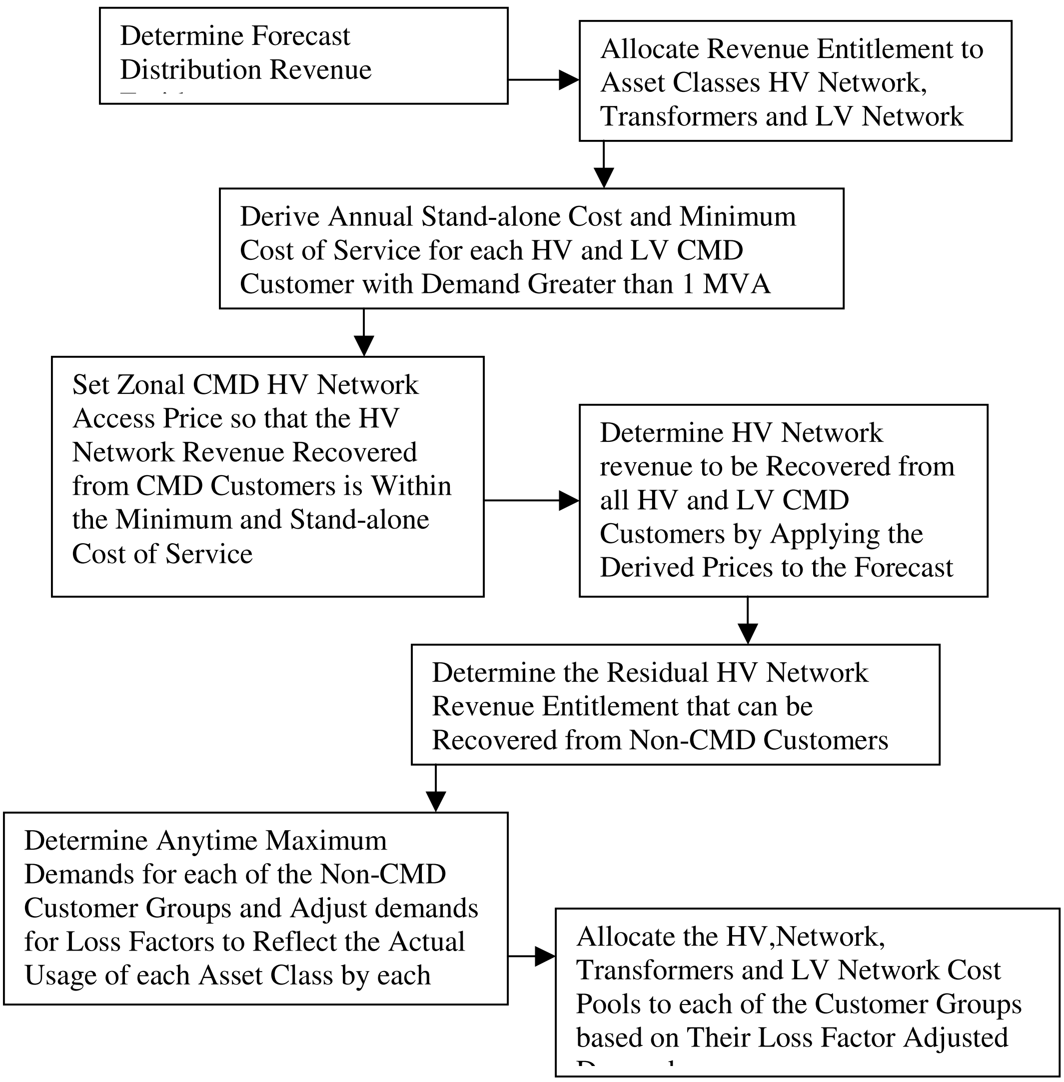
This is defined to include the mining area surrounding Kalgoorlie, which is supplied at 33 kV and the mining area at Forrestania which is also supplied at 33 kV. It does not include the town of Kalgoorlie.

Distribution Network Cost of Service

As previously indicated the distribution customer groups are:

- High Voltage >1MVA maximum demand
- High Voltage <1MVA maximum demand
- Low Voltage >1MVA maximum demand
- General Business Large (300-1000kVA maximum demand)
- General Business Medium (100-300kVA maximum demand)
- General Business Small (15-100kVA maximum demand)
- Small Business (<15kVA maximum demand)
- Residential
- Streetlights
- Unmetered Supplies

To establish the cost of service for each customer group the process followed is illustrated in the following flow diagram.



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

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

It is assumed at this stage that the forecast distribution network revenue entitlement has been determined in accordance with the approach approved by the ERA in the Access Arrangement. The forecast revenue to be recovered from capital contributions is deducted from the total distribution revenue entitlement to give the forecast revenue to be recovered from tariffs.

Allocate Revenue Entitlement to Asset Classes HV Network, Transformers and LV Network

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

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

In the cost of service analysis, the costs for customers with annual maximum demands less than 1000 kVA are assumed to be uniform across the network whereas costs for customers with demands above 1000 kVA are determined on the basis of their being affected by their location on the network and their relative use of network assets.

On this basis, the HV network costs that can be allocated to customers with maximum demands in excess of 1000 kVA are calculated through a process that ensures that the cost is between the incremental cost of service and the stand-alone cost. This approach is consistent with the requirements of chapter 7 of the Code.

In terms of costs of service analysis this approach is contrary to the approach for customers with demands below 1000 kVA. For these customers the approach is facilitated by allocating the network costs on the basis of sharing the average costs of the network between customers depending on their relative usage of the network components.

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

The approach taken is to derive the HV network incremental and standalone cost for each customer with maximum demand in excess of 1000 kVA. This process will give maximum and minimum revenues that could be recovered from this customer group.

The reality of network pricing is that the actual revenue recovered from these customers should fall between these two values. The actual value is determined by deriving network access prices that, when applied to the forecast customer data will produce charge and revenue outcomes that recover at least the incremental cost of service but do not recover more than the standalone cost of service. The detail of this price setting is contained in the next chapter.

Redefine Revenue Pools

The outcome of the process to date is that the HV network revenue for HV and LV customers with maximum demands greater than 1000 kVA has been forecast. This now results in a reallocation of the network tariff revenue entitlement into the costs pools of:

- HV network cost pool that is recovered from customers with demands greater than 1000 kVA.
- Residual HV network cost pool for customers with demands less than 1000 kVA,
- Transformer cost pool, and
- LV network cost pool.

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

Allocation of Residual HV Network Costs to Customer Groups

This allocation is to reflect the usage of each of the customer groups of the HV network remembering that the costs associated with customers with maximum demands greater than 1000 kVA have already been determined.

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

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

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

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

7.1.8 Fixed and Variable Costs

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

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

Capital related costs (return and depreciation)

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

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

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

Operating and maintenance costs

A proportion of the costs associated with operations and maintenance could be said to be simply because the lines and cables are there, while other costs are clearly load related.

Maintenance work such as routine inspection and repair could be allocated in part for the asset being there and in part to retain capacity. Fault restoration work can be similarly differentiated, depending on the nature of the faults.

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

Resultant cost allocation

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

Allocation of Transformer Costs to Customer Groups:

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

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

Allocation of LV Network Costs to Customer Groups:

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

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

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

Load Group	Cost Weighting
Residential	1
Small business	1
General business - small	1
General business - medium	0.9
General business - large	0.1
Low Voltage >1000 kVA	0.1
High Voltage	0

Street Lighting Costs:

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

7.1.9 Use of Network Costs

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

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

7.1.10 Street Light Asset Costs

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

Metering Costs:

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

Administration Costs:

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

8 Distribution Price Setting

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

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

Price Structure:

Nine categories of distribution network prices have been developed to enable customers with different loads and usage patterns to choose the most appropriate form for them. These are constructed in "tariff" style, with fixed and variable components and are generally compatible with existing forms of customer metering. The CMD tariffs are essentially the same form as current published distribution tariffs for loads >1MVA.

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

TARIFF TYPE	TARIFF COMPONENTS							
	Fixed Component	Energy Only	On Peak Energy	Off Peak Energy	Annual Metered Anytime Demand	Off Peak Discount Factor (%)	Contract Maximum Demand (CMD)	Demand/ Length for ATMD > 1000 kVA
Energy Only Small	*	*						
Energy Only Large	*	*						
Time of Use Energy - Small	*		*	*				
Time of Use Energy - Large	*		*	*				
Metered Demand - LV	*				*	*		*
Metered Demand - HV	*				*	*		*
CMD - LV	*						*	*
CMD - HV	*						*	*
Street Lighting	*	*						
Unmetered	*	*						

All tariffs (other than energy only small, street lighting and un-metered), are available to any size customer provided it has appropriate metering. However, tariff components are set to make each tariff more attractive for particular load sizes.

For example, a metered demand tariff is logically not economical for a domestic customer because of the relatively high fixed component and metering charge.

On the other hand, a larger customer with a reasonable load factor will find either the time of use energy, the metered demand or the CMD tariff more economical depending on their load characteristics.

8.1.1 Energy Only Tariff (Residential or Business)

The energy only tariff is for all customers with any time energy only metering. The tariff comprises a fixed component ($/annum) and a variable component (cents/kWh).

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

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

8.1.2 Time of Use Energy Tariff (Residential or Business)

The time of use energy tariffs are available to all customers with time of use energy metering. They comprise a fixed component ($/annum) and variable on-peak and off-peak energy components (cents/kWh).

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

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

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

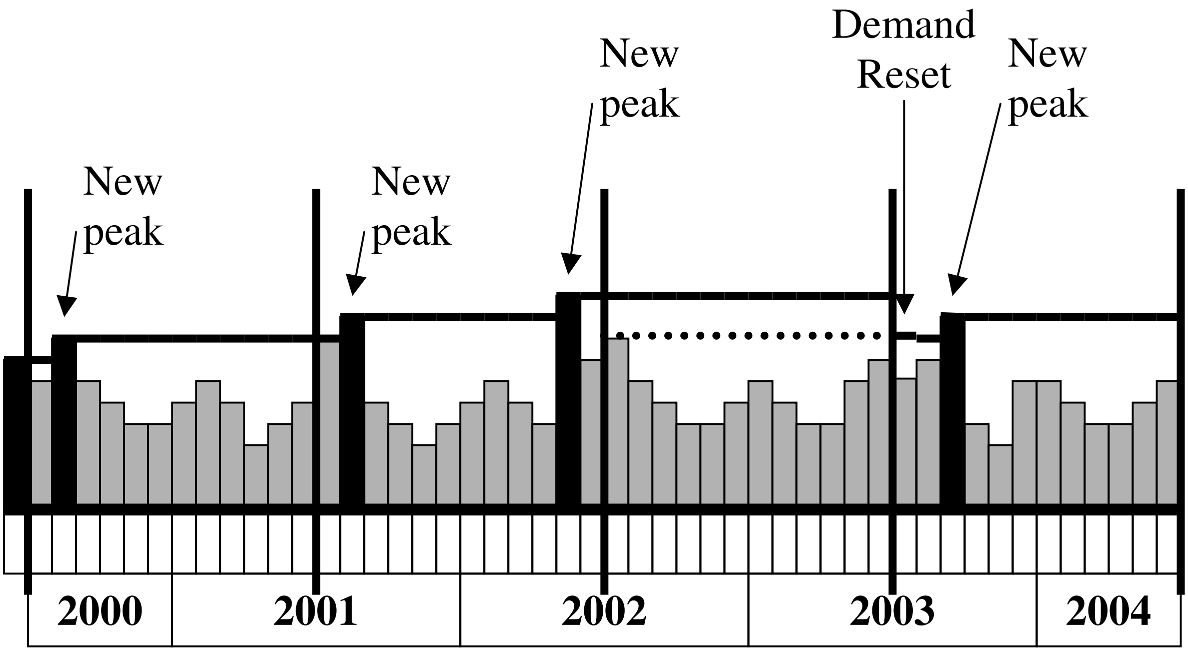
On-peak times are from 8.00am to 10.00pm weekdays, with all other times defined as off-peak.

8.1.3 Metered Demand Tariff (HV and LV)

The metered demand tariff is available to all customers with half-hourly demand metering. It 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 which 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 customers due to the effect of seasonal variation in loads.

The principle of using this rolling peak is illustrated in the following diagram.



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 customers and the negative impact of an extraordinary event would be assessed on a case by case basis.

The off peak discount is applied monthly, based on the metered off peak and total energy amounts. The discount is intended to create an incentive for customers 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 1000 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 300kVA and 1,000kVA and the discount phases out at 1500kVA. At 1500kVA the tariff is set to be less attractive than the CMD tariffs for most customers.

Discount Mechanism:

The discounted network charge is calculated using the following formula.

$$\text{Charge} = (\text{Price} * \text{ATMD}) - \text{Discount} * (\text{Price} * \text{ATMD})$$

Where the discount is defined as:

$(E_{\text{Off Peak}}/E_{\text{Total}}) * DF$ for ATMD< 1000kVA and;

$((1500 - \text{ATMD})/500) * (E_{\text{Off Peak}}/E_{\text{Total}}) * DF$ for 1000< ATMD <1500kVA

DF is the discount factor, and is set at 50%

$E_{Off\ Peak}$ is the total off peak energy for the billing period; and

E_{Total} is the total energy (both on and off peak) for the billing period

8.1.4 Contract Maximum Demand Tariff (HV and LV):

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

The price structure is based on two particular components. There is a component that is directly linked to the nominated maximum demand which is in terms of $/kVA. The second component is based on a combination of the maximum demand and the length of HV feeder from the zone substation to the customer connection. This price component is expressed in terms of $/kVA.km. Both of these tariff components are set to be uniform at 1000 kVA and to be fully cost reflective at 7000 kVA. This structure is consistent with the transmission CMD tariff for distribution connected custromers.

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

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

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

For the demand only component, the price at 1000 kVA is uniform for each of the locational zones and is reflective of the average HV cost of the network per KVA demand. However, as the demand increases, the price declines recognising that the cost of service declines on a per unit basis, as the demand increases.

The demand/length component is set to zero at 1000 kVA. This is consistent with the requirement that all tariffs are uniform below 1000 kVA demand. The price above 7000 kVA is uniform and the price varies continuously between 1000 and 7000 kVA.

In setting the CMD tariffs both components are adjusted so that for each of the customers with demands greater than 1000 kVA, their charge will fall between the incremental and stand-alone cost. The process to derive the settings is described as follows.

Demand Component of the CMD Tariff

The price at 7000 kVA is individually set for each zone. The price is adjusted to provide a best fit so that customers will see a charge that is between the incremental and stand-alone cost. This is done in combination with the demand/length component setting. However it is clear that the price at 7000 kVA should reflect the actual costs of the networks that supply these customers. As such the cost for the CBD zone will be the highest, the Urban zone the next highest and so on so that the rural zone is the cheapest.

At this stage we have the distribution nodal prices at 7,000 kVA. We also have established that the distribution price in terms of $/kVA at 1,000 kVA will be uniform for all customers and will be the same from 0 to 1,000 kVA. The task is to establish that uniform price. At 1000 kVA the demand/length price is zero so the demand price should reflect the average network price for all customers in terms of $/kVA.

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

The anytime maximum demands are not metered for the vast majority of customers with demands below 1000 kVA. The energy consumption is metered and the anytime maximum demands are estimated by applying load factors based on "Industry Codes". The industry codes and associated load factors were developed using sample data for actual representative customer types.

At this stage the size of the revenue pool for customers with demands below 1000 kVA is not established. The revenue pool will be the amount defined by the following formula:

$$RP_{\text{Below }1000} = RP_{\text{Total}} - RP_{\text{Over }7000} - RP_{1000\text{ to }7000}$$

where,

$RP_{\text{Below }1000}$ = revenue to be recovered from customers with demands below 1,000 kVA

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

$RP_{\text{Over }7000}$ = revenue to be recovered from customers with demands greater than 7,000 kVA

$RP_{1000\text{ to }7000}$ = revenue to be recovered from customers with demands between 1,000 and 7,000 kVA

This equation has unknowns in each of the terms at this stage. The revenue pools will only be determined when the CMD tariff settings are established and the prices can be applied to the forecast customer data for customers with demands greater than 1000 kVA. The price at 7000 kVA is set by graphically plotting the charge outcomes for each of the customers with demands above 7000 kVA, in the locational zones, and setting a price that puts the charge outcomes between the incremental and stand-alone cost of service.

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

$$\text{Customer Demand Charge}_{1000\text{ to }7000} = (\text{Price}_{\text{At }1000} * 1000\text{ kVA}) + (\text{Price}_{1000\text{ to }7000} * (\text{CMD}_{\text{Customer}} - 1000\text{ kVA}))$$

where,

Customer Charge $_{1000\ to\ 7000}$ = the demand charge for a customer with CMD between 1000 and 7000 kVA

Price $_{At\ 1000}$ = the average demand price for all customers with CMD below 1000 kVA

Price $_{1000\ to\ 7000}$ = the incremental demand price for this customer with CMD between 1000 and 7000 kVA

CMD $_{Customer}$ = the contract maximum demand for that customer

The Price $_{1000\ to\ 7000}$ will be different for each locational zone but can be calculated by the formula:

$$\text{Price}_{1000\ to\ 7000} = [(\text{Price}_{At\ 7000} * 7000\ \text{kVA}) - (\text{Price}_{At\ 1000} * 1000\ \text{kVA})]/6000\ \text{kVA}$$

So we now have a formula to calculate the price for each customer with CMD between 1,000 and 7,000 kVA with the unknown being the price at 1000 kVA. The price at 7000 kVA has been previously set.

We now have a single unknown (Price $_{At\ 1000}$) that can now be solved in the above equation which now must be expanded as below.

Original Equation:

$$RP_{Below\ 1000} = RP_{Total} - RP_{Over\ 7000} - RP_{1000\ to\ 7000}$$

Expansion of each term:

$RP_{Below\ 1000}$ = $\sum$ Customer anytime maximum demands multiplied by Price $_{At\ 1000}$

RP_{Total} = Total HV network revenue entitlement

$RP_{Over\ 7000}$ = $\sum$ Individual demands for customers greater than 7000 kVA anytime maximum demands multiplied by the zonal price at the zone substation to which the customer is connected

$RP_{1000\ to\ 7000}$ = $\sum$ Customer charges for all customers with CMDs between 1000 and 7000 kVA

At this stage of the process we have the average price at and below 1,000 kVA, the demand price formula for each locational zone for demands between 1000 and 7000 kVA and the zonal price for demands greater than 7000 kVA. This has set the demand component of the CMD tariffs.

Demand/Length Component of the CMD Tariff

The demand/length component of the tariff is set at zero at 1000 kVA. It is also uniform at and above 7000 kVA. The tariff is also designed to be expressed in “rate block” format so that the price is in terms of an incremental price above 1000 kVA and up to 7000 kVA and a uniform price above 7000 kVA.

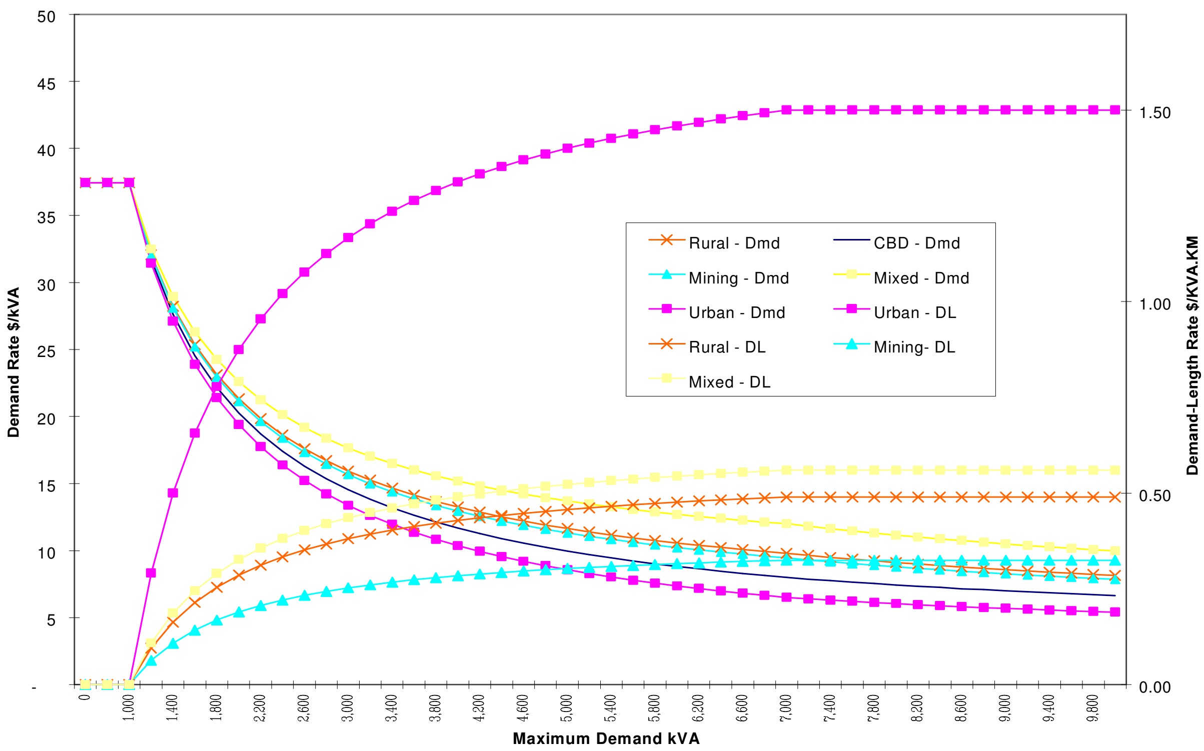
The price between 1000 and 7000 kVA is expressed as:

$$\text{Price}_{1000\ to\ 7000} = [(\text{Price}_{At\ 7000} * 7000\ \text{kVA}) - (\text{Price}_{At\ 1000} * 1000\ \text{kVA})]/6000\ \text{kVA}$$

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

At this stage the price settings are established for both the demand and demand/length price components of the CMD tariffs. The forecast HV network revenue for the HV and LV CMD customers can be calculated by applying the prices to the forecast customer data and summing the charges for all customers.

The prices for both the demand and demand/length components of the prices are illustrated in the following graph.



Metering:

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

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

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

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

In these instances, it is more equitable to recover metering costs via a variable rather than a fixed charge.

The proposed metering price structure is as follows:

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

Administration:

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

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

Street Lighting:

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

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

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

Unmetered:

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

Annual Price Review

As described in the “Network Revenue and Average Price Path Paper” in the Access Arrangement, network revenues are forecast and average prices (“average revenue yields”) are set (regulated) for each of the three financial years in the regulatory term.

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

Distribution prices can be volatile due to matters beyond the control of any one customer. In order to minimise this volatility and reduce the commercial uncertainty for customers, prices are consequently subject to an annual side constraint of plus or minus CPI + 2%.

9 Application and Calculation of any Prudent Discount

A discount to the published access prices may be offered to an applicant seeking access to the network, in accordance with the provisions of the Electricity Networks Access Code 2004.

The discount has no impact on the total network revenue available to Western Power. That is to say, Western Power's regulated target revenue is not affected by this provision.

Code Requirements:

The particular Code provision applying to prudent discounts is clause 7.10.

Prudent discounts

A *service provider* may propose in its *access arrangement* to discriminate between *users* in its pricing of *services* to the extent that it is necessary to do so to aid economic efficiency, including:

(a) by entering into an agreement with a *user* to apply a *discount* to the *equivalent tariff* to be paid by the *user* for a *covered service*; and

(b) then, recovering the amount of the *discount* from other *users* of *reference services* through *reference tariffs*.

Requirements of any Discount Price Offer:

In accordance with clause 7.10 of the Code, the circumstances under which Western Power may offer a discount are described below. The discount must aid economic efficiency, at least to some extent, including the requirement that the price offered must meet the primary pricing objectives of the Code defined in clause 7.3.

Aid to economic efficiency:

Network access prices are designed to reflect costs for the use of the network. Network prices will normally reflect the most efficient cost to transport electricity between generators and load users.

Where the prospective user of the network can demonstrate that a lower cost option is available to that user and the user subsequently takes up the alternative option, there is potential for three possible outcomes:

(a) Where the existing network asset has sufficient capacity to meet the load requirement of the prospective user, the existing asset would remain underutilised compared to the situation where the prospective user had connected to the network,

(b) Where network augmentation is required to provide the new capacity requirement the potential would be lost to construct new network assets that could provide a return to Western Power greater than the incremental cost, or

(c) Western Power is not able to offer a network option that is competitive with the alternative option. Under this scenario the incremental cost to provide a network connection is greater that the cost of the alternative option. The requirements regarding minimum price are described in the next section.

In either circumstance, (a) or (b) above, the loss of utilisation of network assets will result in a loss in opportunity for the network average cost to be reduced. This equates to a loss of opportunity for existing network users to achieve an average price reduction for network access. This potential outcome does not aid economic efficiency for the network.

Primary Pricing Objectives of the Code

The primary objectives of determining prices are contained in section 7.3 of the Code.

Objectives of pricing methods – Primary objectives

7.3 Subject to sections 7.5 and 7.7, the *pricing methods* in an *access arrangement* must have the objectives that:

(a) *reference tariffs* recover the forward-looking efficient costs of providing *reference services*; and

(b) the *reference tariff* applying to a *user*:

(i) at the lower bound, is equal to, or exceeds, the *incremental cost of service provision*; and

(ii) at the upper bound, is equal to, or is less than, the *stand-alone cost of service provision*.

In essence, the Code requires network prices to result in access charges to users that are between the stand-alone cost, and the incremental cost of service provision.

Where Western Power offers a price discount it must still meet the requirements of clause 7.3. A discounted price lower than the incremental cost of service will not be offered.

Spare capacity available

In the case where there is sufficient capacity in the existing network, it is most likely that the incremental cost of supply will be close to the cost of the new connection asset. Not withstanding this, the decision to offer a discounted price, and the amount of that price, will be dependent on the likelihood of future use of that existing network capacity.

Where the existing capacity is likely to be taken up within a reasonable period of time the discount will either;

(a) not be offered, or

(b) will be calculated taking into account the likely future use of the existing network capacity.

New capacity required

In the case where the network requires augmentation to provide the requested service, a discount may be offered provided the discounted price still exceeds the incremental cost of supply.

Calculation of Discounted Price

A discounted price will only be offered if the applicant seeking access to the network is able to demonstrate that an alternative option will provide an equivalent service at a lower price than that offered by Western Power’s reference services and reference tariffs.

The applicant must provide Western Power with sufficient details of the alternative option cost to enable Western Power to calculate the annualised cost of the alternative option determined at a discount rate nominated by the applicant that is equivalent to its internal business discount rate. In any case the discount rate to be used will not be less than Western Power's regulated rate of return.

The price will be set to reflect the cost of the alternative option. However the price must still meet the conditions specified in clause 7.3 that meet the primary pricing objectives of the Code.

Approval of Discount

Information supporting the discount including details of the alternative option will be submitted to the ERA for approval prior to the discount being offered. It is expected that the ERA would treat this information as confidential.

10 Application and Calculation of any Discount for Distributed Generating Plant

Western Power may offer a discount to the published access prices for a user seeking to connect distributed generation to the network, in accordance with the provisions of the Electricity Networks Access Code 2004. The discount is intended to encourage connection of distributed generation by passing the savings in network costs through to the generation user.

The discount has no impact on the total network revenue available to Western Power. That is to say, other users will fund the discount passed onto the user connecting the distributed generation.

Code Requirements:

The particular Code provision applying to distributed generating plant is clause 7.11

7.11 If a user seeks to connect distributed generating plant to a covered network, a service provider must reflect in the user's tariff, by way of a discount, a share of any reductions in either or both of the service provider's capital-related costs or non-capital costs which arise as a result of the entry point for distributed generating plant being located in a particular part of the covered network by:

(c) entering into an agreement with a *user* to apply a *discount* to the *equivalent tariff* to be paid by the *user* for a *covered service*; and

(d) then, recovering the amount of the *discount* from other *users* of *reference services* through *reference tariffs*.

Requirements of any Discount Price Offer:

In accordance with clause 7.11 of the Code, the circumstances under which Western Power may offer a discount are described below.

Savings in network costs will accrue if Western Power has approved forecast capital or non-capital costs within an access arrangement period, that are subsequently not required to be undertaken because of the commissioning of distributed generation. Because of the resetting of the regulatory asset base at the start of each access arrangement period, those savings will not continue beyond the access arrangement period in which the distributed generation is commissioned.

The capital and non-capital savings that occur as a result of the connection of the distributed generation will be passed on in the form of specific annual payment offset against the published access tariffs applying to the generator. The discount will be paid in all circumstances including where the discount exceeds the access charges.

Entitlement to Discount

Western Power will determine the extent of any discount based on the savings in forecast capital and non-capital costs incurred during the access arrangement period that are expected to occur as a result of the connection of the distributed generation.

Calculation of Discount

A discount will be offered if the generator connecting to the network provides cost savings to Western Power compared to the approved costs forecast to be incurred during the access arrangement period.

The annual discount in capital costs will equal the annual savings in capital costs resulting from connection of the distributed generation. The discount will be provided for the remaining term of the access arrangement period. The saving is calculated as the equivalent of the regulated revenue directly associated with the capital costs that would have been incurred without the connection of the generator.

The annual discount in non-capital costs will equal the annual savings in non-capital costs resulting from connection of the distributed generation. The discount will be provided for the remaining term of the access arrangement period.

The discount period may be extended at the discretion of the ERA taking into account the Code provision 7.11 (b).

Approval of Discount

The discount including details of the forecast cost savings and discount period will be submitted to the ERA for approval prior to the discount being offered. It is expected that the ERA would treat this information as confidential.

11 Price Setting for New Transmission Connection Sites

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

However, there is a need for both Western Power and the prospective customer 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 customer requires the price and capital contribution for the purposes of project feasibility, and their internal approval processes.

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

Policy Statement – Transmission Use of System Price (TUOS)

This policy will apply to new transmission connection points where the prospect is that it will be a single customer point. Connection can be at the transmission voltage (132 or 66 kV) or at distribution voltage (6.6, 11, 22 or 33 kV).

(a) 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.

(b) That nominated nodal TUOS price will then be adjusted annually in line with the all capitals consumer price index (CPI).

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

(d) The TUOS price will be published once the connection point is commissioned.

(e) Where another customer subsequently connects to such a connection point the price that will apply will be the price applying to that connection point at the time.

(f) 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 customer or by Western Power, and the customer 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 would be the full cost of construction.

The annual connection price is calculated from the proportion of the regulatory approved maintenance budget to all transmission assets multiplied by the replacement cost of the asset. The allocation in 2005/06 is 2.46% of the full capital cost of the connection asset. Once this price has been determined for a particular connection point, the price is adjusted annually by the all capitals consumer price index (CPI).

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

In this circumstance the customer still retains the option of owning the connection asset. If the customer prefers this option Western Power may require the ability to build connection assets for other users on the same site. Where the customer 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 customer would prefer Western Power to own the connection asset, the connection access price would be the published price that applies to all multi-user substations within the SWIS. This published price would be used by Western Power to calculate the capital contribution for the connection asset.

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