

Ergon Energy Corporation Limited

Network Pricing Principles Statement

To apply for the period 1 July 2005 to 30 June 2010

Release 5

QCA Approved – April 2009

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PREFACE

Ergon Energy has revised its Pricing Principles Statement (PPS) to align with the Queensland Competition Authority's Final Determination, *Regulation of Electricity Distribution* for the second regulatory period 1 July 2005 to 30 June 2010.

This document, while based on the PPS for the previous regulatory period and retaining the basic pricing methodology, has been re-organised to improve the ease of understanding the basic price setting principles.

Any reference to Ergon Energy in this document means Ergon Energy Corporation Ltd as a Distribution Network Service Provider.

Where a section of this document applies to both customers and embedded generators the term "network user" is used. Where the term "customer" is used in a section of this document, that section applies to customers only.

Where this document notes "Network Tariffs" this term is interchangeable with "Network Prices". The term Network Tariffs is used in the publication of rates by Ergon Energy to distinguish them from "Notified Prices" as gazetted by the Queensland Government.

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1 INTRODUCTION

In its Final Determination, *Regulation of Electricity Distribution*, published in April 2005, the Queensland Competition Authority (QCA) required a revised Pricing Principles Statement to be submitted for its assessment and approval.

These pricing principles are used for the development of network prices for all users of the Ergon Energy distribution network (including embedded generators, customers and retailers), for the regulatory period beginning 1st July 2005.

This document covers:

- the background on the need for network prices,
- the network pricing objectives and principles,
- a methodology overview,
- cost allocation methods,
- conversion of costs into network prices,
- capital contribution policies, and
- a future direction for prices.

Ergon Energy is one of two electricity Distribution Network Service Providers (DNSP) that provides distribution services in Queensland. Ergon Energy provides distribution services to over 600,000 customers across an area in excess of 1.6 million square kilometres of regional Queensland accounting for 97% of the state.

Ergon Energy has three pricing zones East, West and Mt Isa regulated by the QCA and an isolated generation zone regulated by the Department of Mines and Energy.

The Mt Isa zone is not connected to the National Grid and as such is excluded from the application of the Rules therefore the National Electricity Market does not operate in this zone, however oversight of network cost to supply for the zone as a whole is carried out by the QCA¹.

All customers supplied by Ergon Energy's isolated generation assets are excluded from the jurisdiction of the QCA and as such are not included in this PPS.

The tariffs that are derived for each of the classes of network users apply to both market and non-market customers and are billed to their retailer.

The Ergon Energy Network Tariff Guide (available from the Ergon Energy web site) provides additional guidance on the application of network tariffs.

Ergon Energy web site: <http://www.ergon.com.au>

¹ See *Electricity Act 1994* s89B

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2 REGULATORY COMPLIANCE

Ergon Energy must comply with the requirements of the QCA both as the economic regulator and as the body responsible for administration of the Queensland Electricity Industry Code (the Code). Ergon Energy must also comply with the requirements of the Department of Mines and Energy which is responsible for issuing and monitoring Ergon Energy's Distribution Authority and any conditions attached to that Authority.

2.1 Revenue and Prices

The amount of revenue Ergon Energy can earn in providing monopoly distribution services is determined by the QCA. This revenue amount is termed the Total Aggregate Annual Revenue Requirement (AARR). The revenue is then recovered through the application of network prices to customers and embedded generators connected to the distribution network.

For the current regulatory period, the QCA has decided to continue with a revenue cap form of regulation based on a 'building block' approach to assessing the future revenue needs of Ergon Energy.

As the name suggests, the building block approach involves attributing costs to the basic components of the business. Typically, this involves establishing the current value of assets employed so as to determine the reasonable return on that investment and the annual loss of value that results from the use of those assets. Since the asset base is not static over time, it is necessary to estimate future capital expenditure requirements over the regulatory period so that the asset base can be updated through time. Finally, it is necessary to arrive at estimates of the operating and maintenance expenditure that will be required across the regulatory period in order to adequately maintain assets and provide the range of services sought by network users. The building blocks include expected efficiency gains but also provide the incentive for the Ergon Energy to further improve its business performance.

In fulfilling its role of Jurisdictional Regulator, the QCA has elected not to apply Part C of Chapter 6 of the Rules (as set out at the time of the Final Determination), instead requiring the DNSPs to submit a Network Pricing Principles Statement to define how network prices will be derived to comply with the requirements of the Final Determination. Appendix 3 details the specific variations to the clauses from Part C. QCA will compare the submitted prices to the PPS and will only approve the use of those prices if they comply with the PPS.

The QCA requires Ergon Energy to adopt side constraints on individual contestable customer distribution price increases to a maximum of CPI plus 5 per cent per year. Under the Final Determination the QCA also required Ergon Energy to propose a price path to transition those customers with prices below cost reflective to the cost reflective price by 30 June 2010.

A position paper was developed on this matter and submitted to QCA for consideration. As a result, the Authority approved individual price movements exceeding the maximum price increase detailed above, for some customers so that all customers would transition to the cost reflective prices by 30 June 2015.

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Ergon Energy has complied with the requirements of the Final Determination by removing side constraints from all prices that apply to non-market customers, bringing any contestable prices that were above cost reflective to the cost reflective price and applying side constraints to other contestable prices where necessary.

This PPS is designed to continue to fulfil the requirements of the QCA and to communicate the framework by which Ergon Energy calculates network connection and access prices during the 2005-2010 regulatory period.

2.2 Network Management Plan

In July 2004, an independent panel, commissioned by the Queensland Government through the Department of Mines and Energy to conduct an inquiry into electricity distribution in Queensland, handed down its report entitled Electricity Distribution and Service Delivery for the 21st Century (EDSD Report). Included in the EDSD Report was a recommendation that a Network Management Plan be published annually. This requirement has since been incorporated into the Code.

The purpose of the Network Management Plan is to detail how Ergon Energy will manage and develop its supply network with the objective of delivering an adequate, economic, reliable and safe connection and supply of electricity to customers. The Network Management Plan is reviewed by the QCA to ensure compliance with Code requirements. Ergon Energy is committed to implementing the Network Management Plan which is available on the Ergon Energy web site.

The Network Management Plan has been published on the Ergon Energy web site in two parts, Part A – Electricity Supply for Regional Queensland and Part B - Network Capability and Planning Report. The network management plans detailed in both these parts have an impact on the future direction of prices.

In Part B it is also intended to facilitate a process for public consultation and stakeholder feedback on network constraints, supply issues and proposed solutions and thereby promote awareness of potential investment opportunities which may be cost effective in avoiding or postponing network expansion.

Ergon Energy will structure its pricing strategies to assist in meeting the objectives of the EDSD Report and the Network Management Plan.

2.3 Minimum Service Standards

The Code contains a suite of minimum service standards which Ergon Energy must use its best endeavours to ensure it does not exceed in a financial year. The purpose of the minimum service standards is to:

- Provide a standard against which Ergon Energy's performance (by feeder type) will be assessed across the supply network; and
- Enable annual comparisons of Ergon Energy's performance.

Ergon Energy will structure its pricing strategies to assist in meeting its performance requirements under the minimum service standards.

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2.4 Regulated Distribution Services

Up to 30 June 2007 the total AARR was divided into 2 parts:

- Services funded by Distribution System Charges (DUOS services and/or Connection Services); and
- Services that are not funded by Distribution System charges (non-DUOS services)

A review of Excluded Distribution Services by QCA in 2007 determined that from 1 July 2007, those distribution services that were classified as non-DUOS services are to be classified as excluded distribution services. These services are subject to a separate regulatory process. As such, the associated forecast revenue for these excluded services has been removed from the existing revenue cap and the AARR adjusted.

This means that the revenue recovered by Ergon Energy under the AARR now only comprises Distribution System Charges (DSC).

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3 PRICING PRINCIPLES

Ergon Energy's objective is to ensure that the allowable revenue is fully recovered from network users in a manner that is:

- economically efficient,
- equitable,
- provides price stability,
- transparent,
- practical and
- easily understood

The distribution network pricing methodology has been developed to meet the objectives by adopting the following pricing principles:

1. *Network Prices should recover no more than the allowable **regulated revenue cap** from the forecast customer base in any one year.*

The recovery of the allowable revenue is achieved through the allocation of costs to the network user classes such that the resulting revenue from the application of prices equals no more than the allowable revenue.

2. *Network Prices should be based on a **well-defined and clearly explained** methodology.*

The purpose of this PPS is to define and explain the methodology that Ergon Energy uses to establish Network prices.

3. *Network Price development should incorporate an **analysis of the cost of service provision** that includes:*

- *definition of the network user classes to which distribution services are provided;*
- *segregation of network costs by voltage level and location;*
- *allocation of the network costs to network user classes and voltage levels; and*
- *translation of allocated costs into service prices.*

Ergon Energy conducts an analysis of its network user and cost base to establish network prices that are an equitable reflection of the network users' use of the existing network and specific dedicated assets, whilst minimising the inefficiency of price averaging.

4. *Prices should signal the economic **costs of service provision** and **promote the efficient use of the network**, by:*

- *being subsidy free (i.e. between incremental cost of supply and stand alone cost of supply);*
- *having regard to the level of available service capacity; and*
- *signalling the impact of additional usage on existing and future investment costs.*

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Network prices for the different classes are designed, within the constraints imposed by the type of metering, to provide signals to the network users on the impact of existing and future network capacity and costs.

5. *Provided that economic costs are recovered, prices should **be responsive to the requirements and circumstances of network user** by:*

- *being a fair and equitable distribution of costs;*
- *being perceived by network users as an equitable reflection of the network users' utilisation of the network assets;*
- *discouraging uneconomic bypass of the distribution network; and*
- *allowing for negotiation, where appropriate, to better reflect the economic value of specific services.*

Network prices reflect the standard level of electricity supply in terms of asset used, quality, reliability and security available to network users at their point of connection to the network.

Where special circumstances exist, network users may negotiate a network price that is different from the published price, for example, if the network user requests a level of service different from the standard level.

6. ***Information** should be **disclosed** on network user class price levels and structures, underlying costs, price derivation methods and rationale, and medium term price paths to ensure:*

- *current and potential network users are able to understand the basis for prices and take account of prices in their consumption, investment and location decisions; and*
- *interested parties are able to better assess the range of economic opportunities for meeting network user requirements that may reduce network users' costs and lead to more efficient outcomes.*

This PPS provides enough information as is necessary for the methodology that Ergon Energy uses to establish Network prices to be transparent to network users. The PPS has been designed to provide a basic explanation in the body of the document with additional information in Appendix 2 for the more technically minded.

7. *Development of prices should ensure **maintenance of price stability and certainty**.*

It is intended that Network Prices remain stable over time to permit network users to make informed investment decisions. It is recognised that price stability means prices will basically only increase by approximately CPI. To achieve this, side constraints are applied to prices to limit price shocks to network users.

8. *Underlying service classifications, cost data, cost allocations and other elements that contribute to pricing decisions should be **periodically reviewed and updated** where relevant to reflect industry developments and changes in network user requirements, expectations and preferences, methods of service provision and costs.*

Each year prior to the preparation of prices for the next annual pricing period, Ergon Energy undertakes a review of the effectiveness of the current price structures and identifies any issues that may have arisen as a result of the use of those prices. If changes are deemed necessary, any changes to the methodology are submitted to QCA for approval and published in an updated version of the PPS prior to the issuing of new prices.

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9. ***The economic signals present in the structure of Transmission Use of System charges (TUOS) should be preserved when allocating transmission charges to distribution customers - to enable customers to interpret, and respond to, those economic signals.***

TUOS Charges are calculated and levied by Powerlink to Ergon Energy. QCA does not regulate transmission charges; however they do have oversight on how these charges are passed through to distribution customers.

Within the constraints of metering type and/or network price, the economic signals inherent in the transmission price structure are passed directly through to the customers to the maximum extent possible given the practical constraint of using average prices for groups of similar customers.

Because customers of Ergon Energy are supplied across a geographically diverse transmission system, the transmission prices vary markedly between transmission connection points. For this reason Ergon Energy separates the Distribution System Charges and TUOS charges into discrete components enabling customers to identify the contribution of the transmission charges to their overall use of network costs.

4 OVERVIEW of the NETWORK PRICE METHODOLOGY

This section provides a high level view of the process used to develop network prices.

4.1 Development of Network Prices

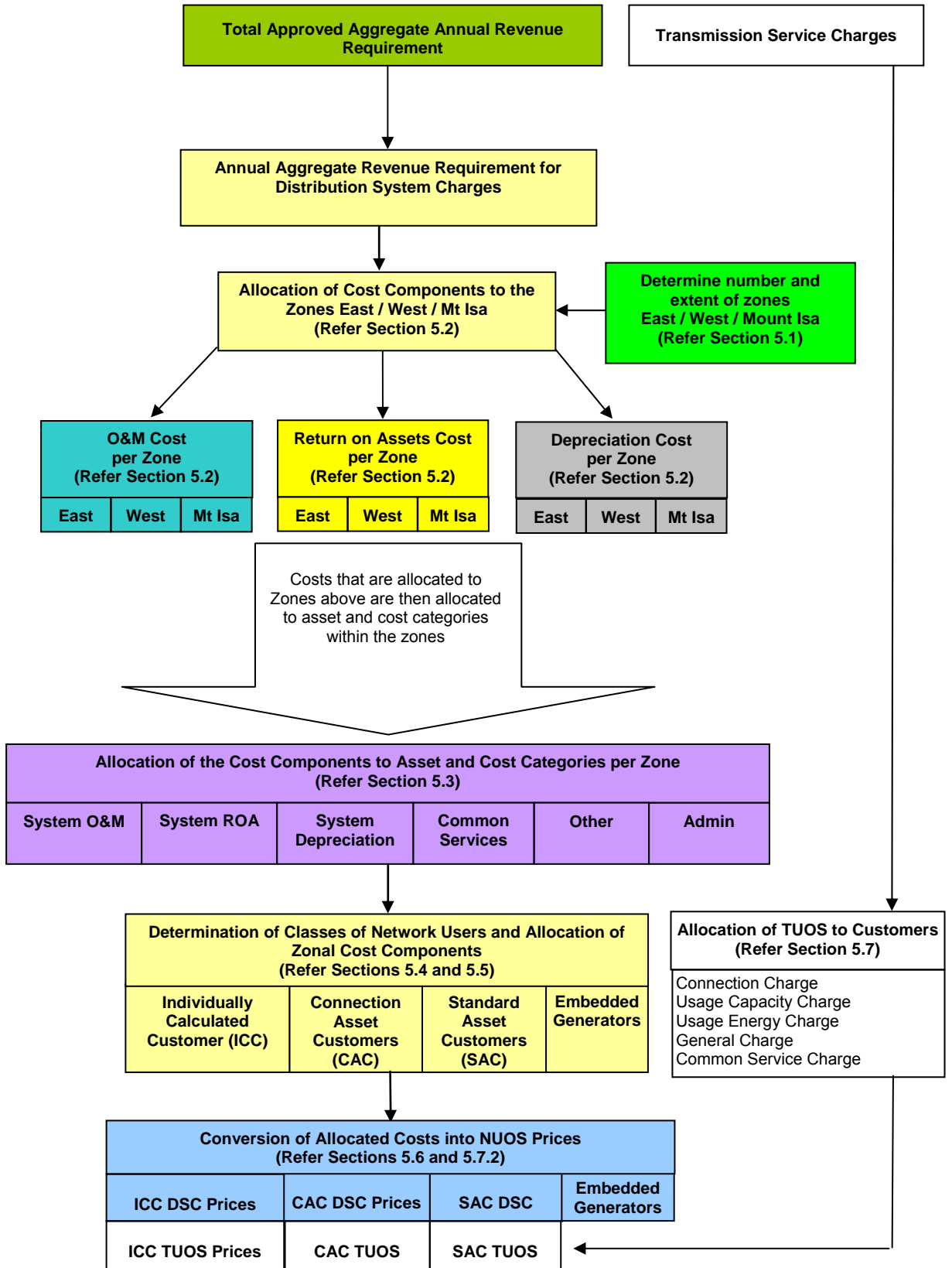
The development of network prices involves seven primary processes, namely:

1. the **determination of zones** where customers have similar cost of supply and cross-subsidisation between the high cost remote networks and the lower cost eastern network is minimised;
2. the **allocation of the cost components** of the approved revenue cap that represent the provision of the connection and access services **to zones**;
3. the **allocation of the zonal costs** across the different **asset and cost categories** within each zone;
4. the **determination of classes of network users** where network users of similar size or similar use of assets are grouped into various network user classes;
5. further **allocation of the network costs within the zones to the network user classes** of those services;
6. the **conversion of these allocated costs into network prices** that recover those costs and are economically efficient; and
7. the **allocation of TUOS to customers** so as to preserve where possible the transmission pricing signals.

The network prices developed under this Pricing Principles Statement are in the main cost reflective in that there is a direct relationship between the network price for the service and the costs of delivering that service (derived through a cost allocation methodology described in Section 5).

This Network Pricing Methodology is depicted in Figure 1 and is detailed in Section 5.

Figure 1 - Network Price Development



5 DEVELOPMENT OF NETWORK USE OF SYSTEM PRICES

The seven primary processes for the development of network use-of-system prices are:

1. Determination of Zones;
2. Allocation of the Cost Components to Zones;
3. Allocation of the Zonal Costs Asset And Cost Categories;
4. Determination of Classes of Network Users;
5. Allocation of the Network Costs Within The Zones to the Network User Classes;
6. Conversion of the Allocated Costs into Network Prices; And
7. Allocation of TUOS to customer.

The building block cost components that contribute directly to network prices and are used to recover the AARR are:

- Operating & Maintenance (O&M);
- Return on Asset (ROA);
- Depreciation (return of assets).

The allowable revenue to be recovered for the above can be found in table 8.4 of the Final Determination, *Regulation of Electricity Distribution*. The net amount of allowable revenue for Return on Assets is the difference between the AARR and the sum of operating expenditure and return of assets.

Extra detail on some of the following process is available in Appendix 2.

5.1 Determination of Zones

The first stage of the overall network price development process is to determine the number and extent of the cost zones to be used for establishing prices in the most efficient and cost reflective way. The detailed work done on determining zones was the subject of a separate report prepared in the year 2000 as a result of QCA's Determination for the first regulatory period. This section highlights the results of that work. The determination of zones is based on a combination of:

- a comparison of the distances the customers are from a transmission connection point (the further from the connection point the more distribution assets required); and
- minimising cross-subsidisation between the high cost less populated remote networks, and the lower cost more heavily populated eastern networks (the further the distance and lower the population density the more expensive the assets and higher the cost to supply); and
- identifying those geographic areas which have a similar cost to supply (remote areas of western and far northern Queensland compared with the higher density eastern areas); and
- simplicity for customers and retailers to understand (based on Local Government Authority areas because the customers usually know who their local government is); and
- identifying a logical "break point" in the electrical supply network (open points in the distribution system that separate different areas of supply).

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During the second regulatory period Ergon Energy has continued with the three zones defined in the first regulatory period with some minor alterations due to improved information in relation to the network supply system. These zones remain broadly based as follows:

- East Zone - includes those Local Government areas where the customers are supplied from the distribution system having a relatively low cost to supply.
- West Zone - includes those Local Government areas outside the East Zone and connected to the National Grid, which have a significantly higher cost to supply than the East Zone.
- Mount Isa Zone - broadly defined as those Local Government areas supplied from the isolated Mount Isa system.

The cost to supply in each of the three zones is analysed as part of the annual price setting process, and may be varied from time to time as cost drivers change, or changes in technology enable more accurate information to be obtained, or for special circumstances which do not fit within the zones existing at the time. Maps defining the zonal boundaries are published on the Ergon Energy web site in the Network Tariff Guide for each pricing period.

5.2 Allocation of the Cost Components to Zones

The second stage in the process is to allocate the cost components of the AARR to each of the zones. The total dollar values for each of the building block cost components that make up the AARR are apportioned across each of the three zones using the following cost drivers;

- O&M – allocated on asset values, customer numbers and energy usage;
- ROA – allocated on asset values;
- Depreciation – allocated on asset values.

Where networks in the West Zone are supplied by shared network systems in the East Zone, the appropriate allocators are used to apportion a share of the cost to both zones

5.3 Allocation of the Zonal Costs to Asset and Cost Categories

The third stage of the overall network price development process is to spread the zone cost across the different asset categories within each zone by first establishing the voltage level asset categories and then allocating the costs to these categories.

5.3.1 Voltage Level Asset Categories

The Rules require that a schedule of Network Tariffs for all classes of distribution services at each voltage level, load class and pricing zone be published each year. To achieve this requirement, the following voltage level asset categories have been established for the allocation of the allowable costs:

- 110/132 kV
- 66 kV Bus
- 66 kV Line
- 33 kV Bus
- 33 kV Line
- 22/11 kV Bus

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- 22/11 kV Line
- Low Voltage
- Services (Low Voltage only)
- Meters & Relays

5.3.2 Sub-division of Cost Components

The O&M, ROA and Depreciation costs are further identified as those that are system related and those that are non-system related.

The allowable costs from the QCA Final Determination are allocated to the voltage level asset categories as follows.

5.3.3 Operating and Maintenance Costs

The QCA has determined an overall efficient operating cost target for Ergon Energy as part of the regulatory review process. To ensure costs are allocated to network users as cost reflectively as possible, the O&M costs are separated into four cost groups with their unique set of cost drivers.

a) **Direct O&M** costs are:

- directly attributable to the provision of network connection and distribution services;
- allocated to the voltage level asset categories based on a combination of historical expenditure and asset values.

b) **Indirect O&M** costs are:

- associated with the provision of network connection and distribution services but cannot be directly attributed to specific asset categories (eg. engineering and supervisory overheads associated with network management);
- allocated to the voltage level asset categories in same proportion as the allocation of the direct O&M costs.

c) **Common Service** costs are:

- associated with those assets that benefit the system as a whole;
- not directly related to any single customer or group of customers (eg. control centres, communications, load control equipment and reactive plant);
- not allocated to the voltage level asset categories but are allocated directly to the customers based on energy usage;
- not applicable to embedded generators.

d) **Administration** costs are:

- the summation of the non-system based costs (eg. corporate overheads, customer services, computer systems, human resources, etc);
- treated as a group as it is impractical to manage a cost allocation process for each of the specific components;
- not allocated to the voltage level asset categories;
- allocated directly to the network users based on hybrid allocation of

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network user numbers and energy usage, and apply to all network users.

5.3.4 Return on Assets

The ROA component of the AARR is separated into three separate cost groups as follows:

a) **System ROA** are:

- the costs associated with the return on system assets employed in the provision of network connection and distribution services;
- allocated to the voltage level asset categories on the basis of asset values.

b) **Common Services ROA** are:

- the costs associated with the return on system assets associated with the provision of common services;
- allocated to the Common Service asset categories on the basis of asset values.

c) **Other ROA** are:

- the costs associated with the return on non-system assets (e.g. vehicles, computers, buildings, etc.);
- allocated to the Other asset categories on the basis of asset values.

5.3.5 Depreciation

The depreciation allowance is also separated into three separate cost groups as follows:

a) **System Depreciation** are:

- the costs associated with the depreciation of those assets associated with the provision of network connection and distribution services;
- allocated to the voltage level asset categories on the basis of asset values.

b) **Common Services Depreciation** are:

- the costs associated with the depreciation on those assets associated with the provision of common services;
- allocated to the Common Service asset categories on the basis of asset values.

c) **Other Depreciation** are:

- the costs associated with the depreciation on non-system assets (e.g. vehicles, computers, buildings, etc.);
- allocated to the Other asset categories on the basis of asset values.

“Common Service” costs for O&M, ROA and Depreciation are grouped together under a single “Common Service” cost category for further allocation to customer classes.

“Other Costs” for ROA and Depreciation are also grouped together under a single “Other” cost category for further allocation to customer classes.

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5.4 Determination of Classes of Network Users

In this fourth stage it is necessary to determine the classes of network users that will be used to recover Ergon Energy's AARR.

Traditionally customer classes have been defined by their end use, for example, domestic, industrial, commercial, etc however network costs are driven by how and when customers use electricity rather than for what it is used.

To provide the appropriate economic and cost of supply signals, four classes of network users have been established, namely:

- Individually Calculated Customers;
- Connection Asset Customers;
- Standard Asset Customers;
- Embedded Generators.

The purpose of the four network user classes is to enable network prices to be developed that provide individual or direct cost of supply signals to those network users where possible while recognising that it is not possible to price every network user individually. There is a trade-off at the distribution level between the complexity of individual price calculation and the inefficiencies created through price averaging. A practical limit also arises in the number of site specific network prices that can feasibly be determined and administered.

Selection of the network users for inclusion in any particular network user class will be at the sole discretion of Ergon Energy.

5.4.1 Individually Calculated Customers

Individually Calculated Customers (ICCs) are those customers:

- a) with energy consumption typically greater than 40 GWh per annum, or
- b) classed as an ICC with energy consumption lower than 40 GWh per annum where:
 - a customer has a dedicated supply system which is quite different and separate from the remainder of the supply network; or
 - there are only two or three customers in a supply system making average prices inappropriate; or
 - a customer is connected at or close to a transmission connection point and the inclusion of the cost of average shared network would increase their network price above stand-alone; or
 - inequitable treatment of otherwise comparable customers arising from the 40 GWh threshold.

ICC distribution prices are based on:

- the actual dedicated connection assets utilised by the customer; plus
- the customer's specifically identified portion of any shared distribution network utilised for the electricity supply.

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5.4.2 Connection Asset Customer

Connection Asset Customers (CACs) are those customers:

- a) with energy consumption typically greater than 4 GWh per annum, or
- b) classed as a CAC with energy consumption lower than 4 GWh per annum where:
 - a customer has a dedicated supply system which is quite different and separate from the remainder of the supply network; or
 - inequitable treatment of otherwise comparable customers arising from the 4 GWh threshold.

CAC distribution prices are based on:

- the actual dedicated connection assets utilised by the customer; plus
- average charges for use of the shared network.

The CAC class of customer is further subdivided into categories based on voltage levels as follows:

- 66kV – connected to either a 66kV substation or a 66kV line
- 33kV – connected to either a 33kV substation or a 33kV line
- 22/11kVBus – connected to either a 22kV or 11kV substation
- 22/11kVLine – connected to either a 22kV or 11kV line

5.4.3 Standard Asset Customer

All other customers are classified as Standard Asset Customers (SACs).

SAC network prices are based on:

- average charges for dedicated connection assets; plus
- average charges for use of the shared network

The categories of network prices used in the SAC price class are:

- Demand High Voltage – any high voltage metered customer; 400kW minimum chargeable demand
- Demand Large – 400kW minimum chargeable demand
- Demand Medium – 120kW minimum chargeable demand
- Demand Small – 30kW minimum chargeable demand
- Volume Large – 26MWh to 100MWh per annum
- Volume Small – 0MWh to 26MWh per annum
- Volume Controlled – Controlled Supply - for those loads that can have the supply interrupted for some periods each day (eg hot water, air-conditioning, pool pumps, etc)
- Volume Night - Controlled – Night Rate Supply - for those loads where supply is generally available for a limited

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- Volume Unmetered – number of hours each night (eg storage hot water)
- Lighting L1 – Unmetered Supply - for small uniform loads as approved by Ergon Energy
- Lighting L2 – Minor Lighting (Ergon Current Standard Lamp Types - Minor Road Lighting)
- Lighting L2 – Major Lighting (Ergon Current Standard Lamp Types - Major Road Lighting)

5.4.4 Embedded Generator

The Embedded Generator (EG) class applies to generators connected to the distribution system.

EGs can be separated into two categories:

- a) EGs that are connected to and only generate into the distribution system;

EG distribution prices are based on identifying:

- the actual dedicated connection assets utilised by the generator

or,

- b) EGs that are connected to, generate for part of the year and take load from the distribution system for the other part of the year.

EG distribution prices are based on identifying:

- the actual dedicated connection assets utilised by the generator

For the load side of the EG, distribution prices are based on identifying:

- the actual dedicated and shared connection assets utilised by the load, depending on the user class category allocated (ICC, CAC or SAC)

5.5 Allocation of the Network Costs within the Zones to the Network User Classes

The fifth stage of the overall network price development process is to allocate or assign the network costs identified in section 5.3 to the network user classes in the most efficient and cost reflective way.

5.5.1 Direct and Indirect O&M, System ROA and System Depreciation Costs

Direct and Indirect O&M costs are grouped together as System O&M costs. System O&M, System ROA and System Depreciation are all allocated in the same way from the voltage level asset categories to the network users as follows:

- ICCs:

For both dedicated connection assets and shared network assets, the costs allocated to the voltage level asset categories are apportioned to the individual customers, using the ratio of the replacement cost of the ICC's dedicated use of the assets to the total replacement cost of assets for the voltage level.

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- CACs:

For CACs, only the dedicated connection assets are specifically identified for the individual customer. The costs allocated to the voltage level asset categories are apportioned to the individual customers, using the ratio of the replacement cost of the CAC's dedicated use of the assets to the total replacement cost of assets for the voltage level.

The shared portion of the costs is an average for the customer voltage category and is based on:

- a) first deducting the allowance for the dedicated assets from ICCs, CACs, EGs and the average connection assets for SACs from the total for voltage level asset categories;
- b) allocating the remainder of the voltage level asset category costs on the basis of the total Any Time Maximum Demand (ATMD) for the customer voltage category compared with the ATMD for the relevant portion of the network at that same voltage level.

- SACs:

For SACs both the connection assets and the shared assets are averaged.

For the connection assets, the costs allocated to the voltage level asset categories are apportioned to the customer kVA category, using the ratio of the replacement cost of the SAC average connection assets to the total replacement cost of assets for the voltage level.

The shared portion of the costs is an average for the customer kVA category and is based on:

- a) first deducting the allowance for the dedicated assets from ICCs, CACs, EGs and the average connection assets for SACs from the total for voltage level asset categories;
- b) allocating the remainder of the voltage level asset category costs on the basis of the total Any Time Maximum Demand (ATMD) for the customer kVA category compared with the ATMD for the relevant portion of the network at that same voltage level

- EGs:

EGs can be separated into two categories:

- a) EGs that are connected to and only generate into the distribution system;

EG costs are based on identifying the actual dedicated connection assets utilised by the generator and any augmentation works or extensions required to be undertaken on upstream assets.

or,

- b) EGs that are connected to, generate for part of the year and take load from the distribution system for the other part of the year.

- EG costs are determined as per a) above.

For the load side of the EG, distribution prices are based on identifying:

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- the actual dedicated and shared connection assets utilised by the load, depending on the user class category allocated (ICC, CAC or SAC)

Where an EG generates for part of the year and takes load from the distribution system for the other part of the year, the connection costs are shared between the EGs output and the load in proportion to the demand for the use of the connection assets.

5.5.2 Common Service Costs

Common Services are required to provide stability and control of the system as a whole. There is no specific driver for these costs however the larger the customer the more likely they are to benefit from the Common Services, therefore these costs are allocated on a “postage-stamp” basis using anytime energy. Common Service O&M, ROA and Depreciation are summed together for allocation as a single cost.

In accordance with the requirements of the Rules, EGs that only generate and do not take load from the network, do not contribute to the recovery of Common Service costs.

5.5.3 Allocation of Admin and Other Costs

Admin and Other costs are two distinct cost groups however their method of allocation is the same. “Admin” is the O&M overhead costs whereas “Other” includes the ROA and Depreciation for the non-system assets.

Admin and Other costs are costs associated with running the business and cannot be directly attributed to specific users or specific user groups. A hybrid allocator of customer numbers and anytime energy is used to allocate these costs. A hybrid allocator is used because an allocation on customer numbers only would move a disproportionate share of the costs to small customers and similarly an energy only allocator would move a disproportionate share of the costs to the very large customers. The weightings have been chosen following investigation into the costs being allocated to ensure that the dollars allocated to the various network user groups adequately reflect the use of these resources.

Admin and Other costs are allocated as follows:

- ICCs:

The requirements for this group’s use of specific Ergon Energy’s Admin and Other resources are independent of individual customer usage and allocated as follows:

- Transmission Network Connection Point (TNCP) ICCs do not use Ergon Energy network assets and therefore do not require the same level of use of Ergon Energy’s Admin and Other resources. An average cost per customer is calculated for this group on the basis of 95% based on the number of Network customers and 5% on anytime energy. The average cost is then allocated to each customer within the group.

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- For Non-TNCP ICCs, a fixed cost per customer is calculated for this group on the basis of 85% based on the number of Network customers and 15% on anytime energy using 40 GWh as the base energy. The fixed cost is then allocated to each customer within the group

- CACs and SACs:

CAC and SAC groups cover a broad range of customers connected at a variety of voltages within the network. As a result, their impact on the use of Ergon Energy's Admin and Other resources is equally varied.

- Costs are allocated to individual customers within these groups on the basis of 85% based on the number of network customers and 15% on anytime energy.

- EGs

EGs have a similar requirement for Ergon Energy's Admin and Other resources as a customer of a similar MW capacity. Accordingly EGs will be classified according to the MW capacity and voltage level of connection;

- EGs have costs allocated on a similar basis as CACs or SACs but because energy output from EGs provides an unreliable allocation factor, the rated generator capacity is used in lieu of the anytime energy.
- To ensure equity between EGs and customers of the same capacity the maximum allocation of Admin and Other costs to an individual EG has been limited to an amount equal to the Non-TNCP ICC allocation.

5.6 Conversion of the Allocated Costs into Distribution System Prices

The sixth process in the development of network prices is the conversion of the costs previously allocated to network users to network prices.

The distributed cost methodology is a reasonable balance between the competing objectives of cost reflectivity in pricing and simplicity. Prices calculated on the basis of this methodology will lie between the “floor” price, which is the incremental cost of supply, and a “ceiling” price which is the stand-alone cost of supply.

- Incremental cost of supply refers to the additional assets required to connect a network user and does not include a share of the existing network.
- Stand-alone cost is the total cost of assets required to connect a network user to the nearest transmission connection point through a dedicated connection.

The network prices developed by Ergon Energy are comprised of a number of components, each selected and structured to provide signals to network users about the efficient use of the network and the impact of their usage on future network capacity and costs.

In developing network prices, Ergon Energy has sought to have the price components signal the impact that the network users will have on the network, whilst:

- a) managing the demand and volume variance risk;
 - b) minimising zonal boundary issues between and within network user classes;
- and

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- c) avoiding any signals that may result in perverse outcomes.

5.6.1 Distribution System Price Components

a) Fixed Charge

The Fixed Charge component is intended to reflect the incremental costs that arise from the connection and management of the network user. This sends a clear signal to the network user about the economic value of the dedicated connection assets. Network users can manage these costs by ensuring that the dedicated connection assets installed match their load and reliability requirement.

For SACs <100MWh, the Fixed Charge also recovers a portion of the shared network costs.

b) Capacity and Actual Demand Charges

Shared network costs for ICCs, CACs and SACs >100MWh are recovered through the Capacity Charge and/or Actual Demand Charge components. These charges provide the economic signals to the customers on the existing and future (next 12 months) use of the shared network on the basis that customers who place greater pressure on the system incur higher charges

The demand used for the calculation of the Capacity Charge is the authorised demand, or if no authorised demand, the annual maximum demand in the previous full pricing period prior to the setting of prices. Under certain circumstances, where there has been a significant change in demand attributable to a network user's load change after this previous pricing period, a more recent demand may be substituted.

The demand used for the calculation of the Actual Demand Charge is the annual average demand, i.e. the average of the monthly maximum demands in the previous full pricing period prior to the setting of prices. Under certain circumstances, where there has been a significant change in demand attributable to a network user's load change after this previous pricing period, a more recent average demand may be substituted.

The Capacity Charge applies to ICC and CAC network users only. For SACs >100MWh a minimum chargeable Actual Demand Charge applies instead of a Capacity Charge.

SACs <100MWh do not have either a Capacity Charge or an Actual Demand Charge because metering for these customers does not provide for the measurement of demand. The shared network component for these customers is recovered through a combination of the Fixed Charge and the Volume Charge.

c) Volume Charge

The Volume Charge is used to recover common service charges and a portion of the Admin and Other charges not recovered in the management costs included in the Fixed Charge. For SACs <100MWh, the Volume Charge also recovers a portion of the shared network costs not included in the Fixed Charge. The Volume Charge applies to the energy (kWh) metered at the customer's installation.

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5.6.2 Network User Distribution System Tariff Structure

a) ICC

- Distribution System Tariffs incorporate customer specific charges for each of the following components:
 - a) a Fixed Charge (\$/day);
 - b) a Capacity Charge (\$/kW of AD/month);
 - c) an Actual Demand Charge (\$/kW/month); and
 - d) a Volume Charge (\$/kWh).

b) CAC

- Distribution System Tariffs incorporate customer specific charges for the fixed charge component and an average for each voltage category for the other components as follows:
 - a) a Fixed Charge (\$/day);
 - b) a Capacity Charge (\$/kW of AD/month);
 - c) an Actual Demand Charge (\$/kW/month); and
 - d) a Volume Charge (\$/kWh).

c) SAC >100MWh

- Distribution System Tariffs incorporate average charges for each of the following components:
 - a) a Fixed Charge (\$/day);
 - b) a Actual Demand Charge (\$/kW/month); and
 - c) a Volume Charge (\$/kWh).

d) SAC <100MWh

- Distribution System Tariffs incorporate average charges for each of the following components:
 - a) a Fixed Charge (\$/day); and
 - b) a Volume Charge (\$/kWh).

e) EGs

For those EGs that only generate into the distribution system, Distribution System Tariffs are based on:

- a) a Fixed Charge (\$/day).

f) Combination Customer and EG

For those sites that, at different times, generate into and take load from the distribution system, Distribution System Tariffs are based on:

- a) a Fixed Charge (\$/day) for the generator output to the distribution system; and
- b) the appropriate Network Price category selected from ICCs, CACs or SACs for load taken from the distribution system.

This method of pricing enables the generator and the load to be billed separately irrespective of whether they relate to a single legal entity's site, or to two separate legal entities at a single site. For example, a generator that delivers energy into the distribution system and supplies energy for the load using waste from the

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associated factory for part of the year. For the remainder of the year, the factory operates as a load with no waste for generation.

5.6.3 Variances from Allocated Cost Based Prices

Consistent with Principle 5 from Section 3, Ergon Energy may negotiate a price other than the price calculated using the cost allocation methodology where it can be demonstrated that the cost based network price is not efficient in that an economic bypass opportunity exists or an alternative energy service could be utilised.

5.7 Allocation of TUOS to customers

The seventh stage in the process is to allocate the TUOS to customers.

5.7.1 Allocation of Powerlink Transmission Costs

The costs allocated to the customers as "TUOS" include a pass through of all charges levied by the Transmission Network Service Provider (Powerlink), which includes, but is not limited to Transmission Use of System charges as defined in the National Electricity Rules.

Transmission Service Charges (TUOS) are allocated on the basis that customers who are able to respond to the TUOS signal should receive the signal. Ergon Energy's network price calculation process passes through TUOS as cost reflectively as possible. TUOS is levied to Ergon Energy by Powerlink at an aggregated level by transmission connection point which means that Ergon Energy needs to devise a methodology to apportion the various components of the TUOS to customers.

The TUOS charges as levied on Ergon Energy have five components:

- Connection Price
- Usage Capacity Price
- Usage Energy Price
- General Energy Price
- Common Service Energy Price

The Connection and Usage Capacity Prices are related to the capacity of the transmission connection point therefore these costs are apportioned to the customers on ATMD.

The Usage Energy Price is a charge based on the actual energy passing through a connection point. These charges are allocated to the customers on the basis of anytime energy.

General Energy Prices and Common Service Prices are charged to Ergon Energy on the basis of historical energy and therefore the charges in any year are fixed. They do not vary with the actual energy passing through the connection point in the billing year. Because both General Charges and Common Service Charges are based on the same historic energy the total Powerlink General & Common Service energy charges are grouped together and allocated to customers on an energy basis.

Although these costs are based on historical energy, the charges for these

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components can only be recovered from current and new customers. These costs are allocated to the customers on the basis of the forecast annual energy with the resultant dollar allocation being included as a fixed amount in customer prices.

For ICCs and CACs Ergon Energy has four towns where a meshed distribution sits below the transmission network meaning that customers can be supplied from different connection points depending on switching arrangements. A weighted average methodology is applied for each of these four (4) locations so that all customers who are to be supplied via the meshed distribution network from more than one connection point have their TUOS price calculated on the same weighted average TUOS rates.

For SACs >100MWh and <100MWh, there are a large number of locational TUOS rates which vary from region to region. The TUOS rates within each geographical region are combined in order to simplify and provide clear TUOS locational signals for these smaller customers.

5.7.2 Network Charges from Other DNSP

In the Toowoomba area, Ergon Energy takes network services from Energex to supply a small group of customers that cannot be economically supplied from the Ergon Energy distribution system. Energex bills Ergon Energy a network service charge on a similar basis to an ICC. To enable these costs to be reflected in customers charges the costs are included with the TUOS charges for this area before being distributed across the customer base in accordance with the TUOS price structure.

5.7.3 Avoided TUOS Usage Charges

Where Ergon Energy becomes liable for an Avoided TUOS Usage Charge payment, the Avoided TUOS amount is collected from the customers connected to the same connection point as the Embedded Generator. The amount collected is in addition to the Powerlink charges and is an amount equal to the Embedded Generator forecast energy output used in the local distribution network multiplied by the relevant Powerlink Usage Energy Price.

Where an Embedded Generator is not eligible for an Avoided TUOS Usage Charge payment, no additional Avoided TUOS amount is collected from the customers connected to the same connection point as the Embedded Generator. In these situations, the Powerlink charge rates are adjusted to account for the Embedded Generator forecast energy output used in the local distribution network.

Embedded Generator Avoided TUOS is explained in Section 6.

5.7.4 Customer TUOS Price Structure

a) ICC

TUOS Tariffs are customer specific and incorporate:

- a) a Fixed Charge (\$/day) for Connection Charge;
- b) a Capacity Charge (\$/kW of AD/month) for Usage Capacity Charge;
- c) a Fixed Common Services and General Charge (\$/day) for Common Services and General Charge; and
- d) a Volume Charge (\$/kWh) for Usage Energy Charge.

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b) CAC

The TUOS Tariff structure for CACs is the same as for ICCs.

c) SAC >100MWh

TUOS Tariffs are averaged at the transmission connection point after the allocation of costs to ICCs and CACs and incorporate:

- a) a Fixed Charge (\$/day) for Connection Charge;
- b) a Demand Charge (\$/kW/month) for Usage Capacity Charge; and
- c) a Volume Charge (\$/kWh) for Common Services, General Charge and Usage Energy Charge.

d) SAC <100MWh

TUOS Tariffs for this category are an average of the remaining TUOS costs to be collected from sum of all transmission connection points and incorporate:

- a) a Fixed Charge (\$/day) for Connection Charge and Usage Capacity Charge; and
- b) a Volume Charge (\$/kWh) for Common Services, General Charge and Usage Energy Charge.

e) EGs

For those EGs that only generate into the distribution system.

- a) TUOS Tariff for generated energy does not apply.

For those EGs that generate into as well as take load from the distribution system

- b) TUOS Tariff for generated energy does not apply.
- c) TUOS Tariff for load taken from the distribution system will be allocated as per the appropriate user class category selected from ICCs, CACs or SACs.

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6 EMBEDDED GENERATOR AVOIDED TUOS

Clause 5.5(h) of the National Electricity Rules requires the Distribution Network Service Provider to calculate "*avoided charges for the locational component of prescribed TUOS services*".

Clause 5.5(i) requires the DNSP to calculate the amount to be passed through to an Embedded Generator

- 1) determining the *charges for the locational component of prescribed TUOS services* that would have been payable by the Distribution Network Service Provider for the relevant financial year if the Embedded Generator had not injected any energy at its connection point during that financial year; and
- 2) determining the amount by which the charges calculated in paragraph (1) exceed the *amount for the locational component of prescribed TUOS services* actually payable by the Distribution Network Service Provider, which amount will be the relevant amount for the purposes of clause 5.5(h).

Ergon Energy proposes to use the following methodology to comply with the NER for Embedded Generators who have sought access to Ergon Energy's distribution network under NER Clause 5.5, who have a generator Connection Agreement with Ergon Energy Corporation Limited that includes a relevant Avoided TUOS payment clause and who are registered as a Generator Rules Participant:

- 1) Determine the amount of energy sent out by the Embedded Generator in the relevant financial year (kWh);
- 2) Convert this to an equivalent amount of energy at the Transmission Network Connection Point (TNCP) by adjusting the sent out energy by the Distribution Loss Factor (DLF) of the embedded generator referred to the TNCP;
- 3) Determine the net generator output, i.e. the generator output that is utilized by the local distribution network by subtracting the actual metered energy that flows back into the transmission network at the TNCP;
- 4) Add the net generation output to the TNCP actual metered data for the financial year;
- 5) Determine the TUOS that would have been charged if the generator was not connected, by recalculating the *customer TUOS usage charges* (demand and energy);
- 6) Subtract the actual TUOS payment from the amount calculated in (5); and
- 7) Arrange payment of the resultant value from (6) to the Embedded Generator.

Note: The demand output from the generator must be considered when determining the Avoided TUOS payment because the *Capacity Charge* is also a locational charge based on demand. However, Powerlink currently uses a nominated demand that is not varied by the output from the generator in the relevant financial year. Because Avoided TUOS is based on the difference between what Ergon Energy would have paid and did pay in the relevant financial year, no allowance can be included for the demand component of the generator output.

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Avoided *customer TUOS Charge* payments to Embedded Generators following the end of the relevant financial year, shall be made as agreed between Ergon Energy and the particular Embedded Generator and may be:

- Lump Sum payment by cheque
- Lump Sum credit against future Network Charges accounts
- Staged payments or credits over a future period.

Costs related to payments to Embedded Generators for avoided *customer TUOS charges* are not part of Ergon Energy's AARR and therefore are required to be recovered under the TUOS recovery process. Refer Section 5.7.3.

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7 APPLICATION OF CAPITAL CONTRIBUTIONS

Where a new customer applies to connect to the Ergon Energy distribution system and the cost of supplying that connection exceeds the average cost for similar existing customers, the new customer may be required to pay a cash capital contribution. Detailed below is an abridged version of the principles for the payment of capital contributions.

A full copy of the Capital Contribution policy is available from the Ergon Energy web site.

7.1 Principles of the Capital Contribution Calculation for Individual Customers

A Capital Contribution from the new customer towards the cost of connection will generally be required where the Project Cost for connection plus a contribution towards upstream shared network costs exceeds the average cost to connect and supply. The contribution to shared network is different for each zone because of the difference in the extent of shared network.

Capital Contributions may be sought from customers where non-standard supply arrangements are being sought or in instances where the Capital Contribution is to be used by way of security if the connection is not of a permanent nature.

7.2 Capital Contribution Calculation – Upstream Shared Network Assets

Where a new customer or developer connection triggers the requirement for Ergon Energy to carry out works on the shared network then the new customer or developer is required to fund all, or a share, of the cost of these works.

Costs may be shared where there are other customers proposed for the shared assets or the shared assets were already planned for the near future.

7.3 Capital Contribution Calculation – Individual Customers' Connection Assets

For the purposes of determining the Capital Contribution for Customers' Connection Assets, the calculation is:

$$CC = ICCS - [IR_{(n=20)} - (IR_{(n=20)} * X\%)]$$

Where:

CC	=	Capital Contribution
ICCS	=	Incremental Costs - customer Specific portion of the Project Cost
$IR_{(n=20)}$	=	Incremental Revenue (present value of a 20 year revenue stream directly attributable to the new connection – calculated on the annual Network Tariff Rates)
X%	=	Percentage contribution to Shared Network Cost

X% for each Zone

East Zone	25%
West Zone	80%
Mt Isa Zone	2%

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Design and construction of **individual** customers' connection assets (which are owned by Ergon Energy upon completion) will be carried out by Ergon Energy.

7.4 Capital Contribution Calculation for Developers

Definition of a Developer

A Developer is anyone (a person, company or any other legal entity) that is arranging an extension of the electricity network where they will not be the final end consumer of the electricity and where Ergon Energy will be providing the revenue metering to each premise in the development. The expectation is that Developers will recoup their costs, including electricity reticulation costs, in the sale or lease price of the lots therefore the developer is responsible for all costs (internal & upstream) associated with making an electricity supply (to Ergon Energy's specifications) available to each allotment or premise.

A development may include, but is not limited to, the following scenarios:

- Urban Residential Development (URD);
- Shopping Centres;
- Multiple Occupancy developments (apartments, units, commercial offices/buildings);
- Broadacre sites (Greenfield/Brownfield sites);
- Remote or Rural subdivisions;
- Commercial & Industrial subdivisions;
- Government projects;
- Strata Title (retirement homes, gated or private communities); or
- High rise developments.

Where there will be a single metering installation (i.e. a single National Metering Identifier) for a multi-premise site and one electricity consumer (a person, company or any other legal entity) enters into a Negotiated Connection Agreement with Ergon Energy (i.e. takes responsibility for 100% of the load at the premises), the extension may be treated as an Individual Customer Connection. (Refer clause 7.1)

Capital Contribution

Developers are responsible for 100% of the cost of providing the electrical infrastructure for their development. The costs associated with the provision of the electrical infrastructure include:

- The Electrical Reticulation inside the development;
- Extension works to get to the development;
- For HV backbone only projects, the cost of the extension works and/or the cost of reserving capacity for the development;
- Upstream augmentation of the existing distribution system to provide capacity in the distribution system to supply the development; and,
- Any tree clearing and any other costs attributable to the development.

Upon completion of the Electrical Reticulation inside the development Ergon Energy becomes responsible for operation and maintenance of the assets. Some of these assets will be built by the developers and given to Ergon Energy as a non-cash contribution.

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7.5 Capital Contribution Cost Sharing

Where an extension or augmentation financed by previous customers benefits a subsequent customer, then the subsequent customer may be required to provide compensation to the previous customers when and if the subsequent customer takes supply within a defined time period.

The assets to be considered for cost sharing are those assets that can logically and economically be shared by the customers in the group as if they were arranging the extension and/or augmentation at the same time.

The main points for cost sharing are:

- The Cost Sharing Period is five (5) years from the date of connection of the initial customer in the group.
- All cost sharing on the extension is based from the date of connection of the original customer to the distribution network.
- Cost sharing normally only applies within each separate high voltage extension.
- Cost Sharing is dependant on the relationship between the customer segment for the original customer and the customer segment for the subsequent customer.
- Allocation of the individual customer share is based on the extent of the customer's use of the network system as if the subsequent customer was part of the original group.
- The value of the reimbursement to the original customer is calculated by subtracting the revised contribution for each member of the new group from the original contribution made by the original customers.
- The value of the reimbursement is time-adjusted from the date the original customer was connected to calculate the subsequent customer contribution amount.
- The value of the contribution from the subsequent customer and the reimbursement to the original customers is reduced over the cost sharing period to zero.
- The amount of the cost sharing reimbursement to each customer shall not exceed the whole dollar amount of the original contribution made by that customer.
- Developers do not receive benefits from Cost Sharing but may be required to make a Cost Sharing contribution.

7.6 Recognition of Capital Contribution in Prices

Most of the Capital Contributions are received from customers who seek access to average SAC prices therefore the value of these contributions is recognised in network prices through a reduction in the SAC allocated costs.

For non-cash Capital Contributions, the value of the contributed assets are treated in the same way as cash Capital Contributions and the value is also recognised in SAC allocated costs.

For ICCs, CACs and EGs the asset costs are specifically included in the site specific network charges. Whether or not a Capital Contribution is required from these network

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users will be determined as a result of individual negotiations for a Connection and Access Agreement covering the new connection.

Recognition in the individual prices for any Capital Contributions paid by ICCs, CACs or EGs under these arrangements will be in accordance with the requirements of the National Electricity Rules.

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8 ANNUAL APPROVAL PROCESS

Ergon Energy will submit annually a Schedule of Network Prices that is to apply in the following financial year.

Ergon Energy will demonstrate in the Schedule of Network Prices that the proposed prices comply with the methodology in this Pricing Principles Statement by providing supporting information extracted from the DCOS model together with explanatory information.

The timelines below will apply to issuing of annual Network Prices.

The dates for the annual approval process are as follows:

- 31 Dec Ergon Energy submits any amendments to the Pricing Principles Statement
- 31 March Ergon Energy submits to QCA the proposed Schedule of Network Prices for the coming financial year
- 25 May Approval from QCA if satisfied that the proposed prices comply with the Pricing Principles Statement
- 31 May Ergon Energy publishes the Network Tariff Rate Listing for the coming financial year

Included in the annual Schedule of Network Prices submission, Ergon Energy provides:

- data and information on how the proposed prices are calculated (including examples);
- a reconciliation of revenue from each network user group with the AARR;
- the proposed Schedule of Network Tariffs, including terms and conditions, to be published;
- demonstration that the network prices lie between the economic boundaries of "floor" and "ceiling" prices; and
- a demonstration that the proposed prices are within any applicable side constraints.

9 FUTURE MOVEMENT IN PRICES

9.1 Price path for ICCs and CACs

There are still a number of network users that have prices below the allocated cost. A position paper was developed on this matter and submitted to QCA for consideration. As a result of discussions with the Authority, individual price movements exceeding the maximum price increase detailed in the Final Determination, have been adopted for some customers.

9.2 Network Price Structure

In addition to the alignment of prices to cost, the network price structure will be reviewed from time to time to determine if different price structures are able to promote a more efficient use of the network and to send the appropriate demand signals to customers. To facilitate this Ergon Energy has developed a Medium Term Pricing Strategy which considers:

- Enhanced and extended load control system;
- Power factor correction program;
- Demand side management (DSM) programs; and
- Review of demand tariffs.

Further analysis from this review will determine if a different price structure is more appropriate to send additional signals to customers of their impact on the costs associated with the provision of network services.

9.3 Standard Price for Small-Scale Embedded Generators

Much work is being carried out across Australia into the costs and benefits of Embedded Generators. Depending on the results of these investigations, it may be beneficial to introduce a standard network price structure for small-scale generators. Any network price structure developed for Embedded Generators will be consistent with the approach taken within the broader National Electricity Market environment.

Generators both large and small impose additional constraints on the operation of the distribution network when compared with customers so careful consideration will be required before a standard pricing structure could be introduced.

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APPENDIX 1 - GLOSSARY

AARR	Aggregate Annual Revenue Requirement is the calculated total annual revenue to be earned by Ergon Energy for distribution services and administered by QCA
ACCC	Australian Competition and Consumer Commission as established under the Trade Practices Act 1974 (Commonwealth).
Any Time Energy	Is the amount of energy consumed by the customer irrespective of time of day.
Any Time Maximum Demand	Is the maximum half hourly demand for a customer that occurs at any time within the pricing period.
B2B Transactions	Business-to-Business transactions are those transactions carried out in accordance with the B2B Procedures under the National Electricity Rules, or as otherwise agreed between the parties.
Capital Contribution	Up-front payment that may be required to be paid by network users to cover above average costs associated with connection to the distribution/transmission network
Rules	National Electricity Rules - market rules governing the operation of the National Electricity Market
Coincident Demand	The demand on an electrical system as a result of the summation of each individual customer's demand at a specific point in time. This is different from the numerical sum of all customers' anytime maximum demand because each customer reaches their maximum demand at different times.
Common Service	A service that ensures the integrity of the distribution system and benefits all customers and cannot reasonably be allocated to customers on a locational basis.
Connection Service	An entry or exit service as defined in the Rules
Contestable Customer	A customer who is able to choose a Retailer for the energy component of their electricity charges including eligible customers who have not yet entered the electricity market.
CPI	Consumer Price Index
CRNP	Cost Reflective Network Pricing. A cost allocation method which reflects the value of assets used to provide transmission and distribution services to Network Users.
Customer Connection and Access Agreement	Agreement between the Ergon Energy DNSP business and a customer
DCOS	The Distribution Cost of Supply model which consists of a number of interconnected Excel workbooks used for modelling the network prices.

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Deep Connection Assets	Additional assets, other than the dedicated assets, that may be allocated to embedded generators where these assets would not have been required if the embedded generator was not connected.
Demand	Measurement of customer peak load taken as the average load over a half-hour period measured in kW or kVA
Distribution Network	The electrical system used to transport electricity from the high voltage transmission network connection point to distribution network users
Distribution System Charge	Charge which covers connection services and or DUOS services.
DNSP	Distribution Network Service Provider - Entities established under licence to distribute electricity
DLF	Distribution Loss Factor – factor applied to customers’ metered energy consumption to determine total energy purchases at the transmission connection point that accounts for losses in the distribution network.
DUOS	Distribution Use of System Charge - Component of network access charge which covers use of the distribution network.
EG	Embedded Generator – Generator or co-generator which is connected to the distribution network instead of the transmission network.
Electricity Market	Means the National Electricity Market as administered by NEMMCO
FRC	Full Retail Competition
GWh	Gigawatt hour = 1,000,000 x kilowatt hour.
Incremental Cost of Supply	Costs of additional connection assets required to connect a new network user to the shared network. Does not include shared network costs.
kV	kV = 1,000 Volts.
kVA	kVA = 1,000 Volt-Ampere which is a measure of the apparent power flow which is a measure of the total capacity required to supply a customer’s load.
kW	kW = 1,000 Watts which is a measure of the real component of power being consumed by the consumer’s load.
Load Factor	measure of the percentage of time a load is used in any given period. Loads used 24 hours per day, 7 days a week have a load factor of 1 or 100%.
Market Customer	A customer who is party to a negotiated retail contract under the <i>Electricity Act 1994</i>
MWh	Megawatt Hour = 1000 x kilowatt hours.

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National Electricity Rules	The code of conduct approved by Ministers of the participating jurisdictions in accordance with section 6(1) of the National Electricity Law. The National Electricity Code has been reviewed and replaced by the National Electricity Rules.
NEMMCO	National Electricity Market Management Company, responsible for the implementation of the Rules and the day to day operation of the National Electricity Market.
Network User	A Generator, a Transmission Customer, a Distribution Customer or a Market Network Service Provider.
Non-market Customer	Means a customer who is not party to a negotiated retail contract under the <i>Electricity Act 1994</i> and is subject to the Notified Prices set by the Minister of Mines and Energy.
NUOS	Network Use of System Charge - Total network access charge which covers use of both the distribution network and the transmission network.
postage stamp basis	A system of charging <i>Network Users</i> for transmission service or distribution service in which the price per unit is the same regardless of how much energy is used by the <i>Network User</i> or the location in the transmission network or distribution network of the <i>Network User</i> .
Power Factor	The ratio of the active power to the apparent power at a metering point. Optimum power factor is unity.
Powerlink Queensland	Transmission Network Service Provider that provides transmission services in Queensland
Retailer	Means a company which is licensed to sell electricity. A retailer may be the retail subsidiary of a distribution business or an independent retailer.
Revenue Cap	The total annual revenue requirement for a year determined by the QCA for prescribed services.
Stand Alone Costs	The costs associated with providing a single dedicated supply between the network user's installation and the nearest transmission connection point. Stand alone costs include the connection assets and the provision of upstream network that would normally be shared with other customers.
Side Constraints	Constraints set down by QCA in its Final Determination to limit price shocks to network users.
TLF	Transmission Loss Factor – factor applied to customer's metered energy consumption to determine total energy purchases from the electricity pool, taking into account losses in the transmission network.
TNSP	Transmission Network Service Provider – Powerlink is the TNSP in Queensland.

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TUOS	For this PPS, TUOS means all components of the transmission network access charge which form part of the Transmission Service Charges levied by the TNSP.
WACC	Weighted Average Cost of Capital. Measure of the required rate of return on assets based on assessment of the cost of debt and equity.

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APPENDIX 2 – ADDITIONAL PRICING INFORMATION

1 Cost Allocators for Network Use of System Services

There are a range of cost allocators that can be used in a Distribution Cost of Supply model such as that used by Ergon Energy. The selection of the appropriate allocator is based on the ability of that allocator to reflect the relationship between various costs and what causes those costs to occur. The range of possible allocators includes:

- a) number of customers;
- b) anytime energy;
- c) period energy (time of use);
- d) anytime maximum demand;
- e) period demand (time of use);
- f) coincident demand; and
- g) replacement cost of assets.

The customer numbers and usage are identified for each zone from an interrogation of the customer information system based on the customer's geographic location. The value of the assets for each zone are determined from an interrogation of the asset management database that was used to provide QCA with the information required for input to the Final Determination.

Ergon Energy has adopted the following allocators in the DCOS model:

- a) number of customers,
- b) anytime energy,
- c) anytime maximum demand, and
- d) replacement cost of assets.

The reasoning behind the selection of these allocators is as follows:

1.1 Number of Customers

This allocator is appropriate for those costs that are dependent upon or driven by the number of connected customers. Ergon Energy has a number of costs that are customer number based, including a significant proportion of the overhead costs of the business that are driven by the number of staff and systems required to serve the customer base.

1.2 Anytime Energy

This has been used as an allocator for those costs that are related to the size of the customer but not specifically to the demand that customer places on the network, for example, the common service costs. In addition, consistent with the recovery mechanisms used in the electricity market, those costs that cannot be directly related to a product or service are recovered through the use of anytime energy prices (e.g. some overhead costs). A portion of TUOS is also allocated to customers on an anytime energy basis for those energy related TUOS charge components billed to Ergon Energy by the Transmission Network Service Provider so as to retain the transmission pricing signals in customer tariffs.

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1.3 Any Time Maximum Demand (ATMD)

This method of allocation is used for the shared system costs. The basis for this is that network development in each part of the network is driven by peak demand in that part of the network. For example, in a domestic area the shared network capacity is based on the peak domestic demand that generally occurs for Ergon Energy on winter nights in the southern areas of the state and summer evenings in the northern areas of the state. By contrast in commercial/industrial areas the shared network capacity is generally determined by summer day peak demands.

These individual demands throughout the network combine to form an overall coincident system peak demand; however the coincident demand is more relevant to transmission network capacity than distribution.

Whilst the ideal cost allocation mechanism would be based on a real time model which constantly monitors the network demands at specific locations, such an approach is not achievable at present and ATMD provides a simple, and reasonable basis for apportioning system usage related costs. It reflects the fact that demand is the primary driver of shared network costs. A portion of TUOS is also allocated to network users on an ATMD basis for the demand related TUOS charge components applied to Ergon Energy by the Transmission Network Service Provider so as, once again, to retain the transmission pricing signals in network user prices.

1.4 Replacement Cost of Assets

The replacement costs of the assets are used merely as allocators to apportion O&M, ROA and Depreciation costs across the various cost categories.

The replacement costs are not used directly to calculate the value of any of the costs within the price allocation model.

The replacement costs are used to allocate the O&M, ROA and Depreciation costs because the replacement costs are relatively stable over time whereas the depreciated values change. If the depreciated values were used the network user prices would vary up and down depending on when old assets were replaced with new assets. The actual age and value of the assets used to supply a network user is not relevant to the prices charged for that network user because Ergon Energy is required to maintain supply to the network user in accordance with statutory and Rules requirements irrespective of the type or age of assets deployed.

An example of replacement costs used in the allocation of O&M is shown below.

$\text{O\&M Allocation for Voltage Level} = \text{Total O\&M \$ allowance} \times \frac{\text{RC of Assets for Voltage Level}}{\text{RC of Total Assets}}$
--

Where RC = Replacement Cost

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2 AARR Cost Components to DCOS Cost Categories

The Distribution Cost of Supply (DCOS) categories are the categories used in Ergon Energy's pricing model to allocate the allowable costs to the various network user classes. Table 1 shows how the allowable AARR and TUOS cost components are divided into the various cost groups for further allocation to the DCOS cost categories.

Table 1 – AARR Cost Components to DCOS Cost Categories

Revenue Cap Components ↓	Cost Groups ↓	DCOS Cost Categories						
		Distribution System Charges						TUOS
		System O&M	System Depreciation	System ROA	Common Services	Admin	Other	TUOS
O&M Section 5.3.3	Direct	✓						
	Indirect	✓						
	Common Services				✓			
	Administration					✓		
ROA Section 5.3.4	System Assets			✓				
	Common Services				✓			
	Other Assets						✓	
Depreciation Section 5.3.5	System Asset		✓					
	Common Services Asset				✓			
	Other Assets						✓	
TUOS Section 5.7	Transmission Use of System Charges							✓

3 Cost based Network Prices

Network prices developed using the process described in the PPS are categorised as cost based. To be economically efficient the network prices should lie between the boundaries established by the stand alone costs (ceiling) and incremental costs (floor).

As a result of the cost allocation methodology described in this Pricing Principles Statement, if there is some network capacity available then the incremental costs associated with a new network user will be the costs of connection and the costs of maintaining that new network user. The fixed or standing charge includes these costs, making it the floor price. Any use of energy from the network will incur additional charges taking the charge paid by the network user above the incremental cost of supply (the economic cost floor).

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Smaller Customers (<=22 kV)

In the case of smaller customers connected at the distribution level (generally 22 kV and below), the allocated cost of supply will be well below stand-alone costs of supply. The stand-alone costs for a small customer would include costs associated with dedicated upstream infrastructure. These upstream costs are shared between many customers in the case of the fully allocated model hence the allocated cost model should always lay below the stand-alone cost.

Larger Customers (>=33 kV)

For larger customers connected at the sub-transmission level (33kV and above), the allocated cost model includes a site-specific component of supply network costs. Individually Calculated Customer cost based prices are determined by mapping the actual supply network and allocating the relevant proportion of costs to the customers on the basis of their use of that network. Therefore as there is an allocation of costs, and/or the full network costs are allocated in the case of a single customer asset, the ICC network prices must be equal to or less than the stand-alone cost of supply (economic cost ceiling).

The cost based prices for Connection Asset Customers take into account the specific connection costs as well as an allocation of the upstream shared network costs. On a similar basis to the smaller customers, the allocation of upstream shared network costs will result in individual network prices being less than a stand-alone ceiling cost for the CAC group because of the sharing with many other customers.

Costs associated with the operation and maintenance of the different classes of assets are allocated to the voltage level cost groups so that these costs are reflected in the Network price for the customers who use these assets. For example, a customer taking supply at **33 kV** will be allocated a proportion of all of the upstream costs (33kV, 110kV, etc) whereas a customer taking supply at 110kV will be allocated their proportion of the 110kV system costs only, not downstream system costs, as they do not use those parts of the system.

4 Background to Price Structure

4.1 Fixed Charge

The **Fixed Charge** components adopted are intended to reflect the incremental costs that arise from the connection and management of the network user. This sends a clear signal about the economic value of the dedicated connection assets and provides a stable price and income to Ergon Energy regardless of the usage of the network. Network usage signals are provided by other price components. Network users can manage these costs by ensuring that the dedicated connection assets installed match their load and reliability requirement.

4.2 Capacity Charge and Actual Demand Charge

As noted in section 5.6.1 (b), shared network costs for ICCs, CACs and SACs >100MWh, are recovered through the **Capacity Charge** and/or **Actual Demand Charge** components. These charges provide the economic signals to the customers on the use of the shared network.

An **Actual Demand Charge** is levied on the basis that customers who place greater pressure on the system should incur higher charges. Network expansion becomes necessary where there is a likelihood of demand exceeding available capacity. While this demand fluctuates over time, the critical supply level to be provided is the

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aggregated network usage during peak times. Co-incident peak demand is, therefore, the driving factor behind system augmentation. In this context, customers should be charged according to their contribution to this threshold demand level. In a practical sense, while there are limitations associated with determining an individual customer's contribution to co-incident peak demand, the maximum demands of those customers are an appropriate proxy. Accordingly, the demand charge levied is determined by the relevant user's peak demand recorded in any half hour period during the month.

However, one drawback of demand charges is that they fail to assign an adequate share of costs associated with system augmentations to customers with low load factors who impose maximum demands on the system at infrequent intervals.

The load factor is the ratio of the average consumption to peak demand consumption, and measures the variability of a customer's consumption. A low ratio, for example less than 0.4, suggests a variable consumption pattern while those closer to unity (1.0) identify more constant energy usage.

A capacity charge is similar to a demand charge but more effectively takes into account the impact that these low load factor customers have on system augmentation. It sends signals to these customers that they can reduce their network charges by reducing the variability of their consumption, as this lowering of peak demand reduces the pressure that they place on the network.

The demand used for the calculation of the Capacity Charge is the authorised demand, or if no authorised demand, the annual maximum demand in the previous full pricing period prior to the setting of prices. Under certain circumstances, where there has been a significant change in demand attributable to a customer's load change after this previous pricing period, a more recent demand may be substituted.

The demand used for the calculation of the Actual Demand Charge is the annual average demand, i.e. the average of the monthly maximum demands in the previous full pricing period prior to the setting of prices. Under certain circumstances, where there has been a significant change in demand attributable to a network user's load change after this previous pricing period, a more recent average demand may be substituted.

The Capacity Charge applies to ICC and CAC network users only. For SACs >100MWh a minimum chargeable Actual Demand Charge applies instead of a Capacity Charge. The shared component of costs for SACs > 100MWh is recovered in the Actual Demand Charge which is a combination of a fixed amount due to the minimum chargeable demand and a variable amount due to the monthly variation in usage.

SACs <100MWh do not have either a Capacity Charge or an Actual Demand Charge because metering for these customers does not provide for the measurement of demand. To maintain consistency of application for SACs < 100MWh the shared component for these customers is recovered through a combination of the fixed charge and the volume charge.

4.3 Volume Charge

Volume Charges have been adopted to recover those costs that are allocated on a non-distortionary basis, as well as any residual allocated costs that are relative to the "size" of the customer but not specifically their network demand after the Fixed and Demand Charges have been calculated (eg Admin and Other costs, see Tables 1 & 2). The volume charge applies to the energy (kWh) metered at the customer's installation.

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Table 2 shows the allocation of the DUOS cost categories to the various price components for DUOS recovery.

Table 2 – Conversion of DCOS Cost Categories to Distribution System Prices

DCOS Cost Category		Distribution System Price Components			
		Fixed or Charge	Capacity Charge	Actual Demand Charge	Volume Charge
		\$/day	\$/kW	\$/kW	c/kWh
System O&M	Connection Assets	●			
	Shared Assets ICC & CAC		●	●	
	Shared Assets SAC >100MWh			●	
	Shared Assets SAC <100MWh	●			●
System Depreciation	Connection Assets	●			
	Shared Assets ICC & CAC		●	●	
	Shared Assets SAC >100MWh			●	
	Shared Assets SAC <100MWh	●			●
System ROA	Connection Assets	●			
	Shared Assets ICC & CAC		●	●	
	Shared Assets SAC >100MWh			●	
	Shared Assets SAC <100MWh	●			●
Common Services					●
Other		●			●
Administration		●			●

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Table 3 shows the allocation of the Powerlink price components to the customer price component for TUOS recovery.

Table 3 – Conversion of Powerlink Cost Categories to TUOS Prices

Powerlink Cost Category		TUOS Network Price Components				
		Fixed Charge	Capacity Charge	Common Service and General Charge	Demand Charge	Volume Charge
		\$/day	\$/kW	\$/day	\$/kW	\$/kWh
Connection Charge	ICC	●				
	CAC	●				
	SAC >100MWh	●				
	SAC <100MWh	●				
Usage Capacity Charge	ICC		●			
	CAC		●			
	SAC >100MWh				●	
	SAC <100MWh	●				
Usage Energy Charge	ICC					●
	CAC					●
	SAC >100MWh					●
	SAC <100MWh					●
General Energy Charge	ICC			●		
	CAC			●		
	SAC >100MWh					●
	SAC <100MWh					●
Common Energy Charge	ICC			●		
	CAC			●		
	SAC >100MWh					●
	SAC <100MWh					●

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4.4 Price Components for Network Users

Table 4 shows which price components are applicable to each class or category of network user prices.

Table 4 – Network Price Components

Network Price Component	Description	Network user Classes to which Network Price Component is applicable								
		ICC	CAC	SAC >100MWh	SAC <100MWh	Controlled Supply	Night Rate Supply	Unmetered	Street lights	EG (Generation only)
Fixed Charge \$/day	<u>Distribution System Charge</u> Reflective of the costs associated with the connection assets (entry and exit services) and network user management services	●	●	●	●	●	●	●	●	●
	<u>TUOS</u> a portion of the allocated TUOS costs.	●	●	●	●					
Capacity*# Charge \$/kW/month	<u>Distribution System Charge</u> Reflective of the network capacity required by the network user on a long term basis and levied on the basis of an authorised demand.	●	●							
	<u>TUOS</u> a portion of the allocated TUOS costs.	●	●							
Common Service and General Charge \$/day	<u>TUOS only</u> a portion of the allocated TUOS costs.	●	●							
Actual Demand* Charge \$/kW/month	<u>Distribution System Charge</u> Reflective of the costs of network capacity availability and limitations.	●	●	●						
	<u>TUOS</u> a portion of the allocated TUOS costs.			●						
Volume Charge (\$/kWh)	<u>Distribution System Charge</u> Recovery of costs not directly allocated or associated with network drivers, through a non-distortionary basis. The charge also includes costs that are proportional to the size of the customer, such as customer management.	●	●	●	●	●	●	●	●	
	<u>TUOS</u> for ICCs, CACs and SACs >100MWh, a portion of the allocated TUOS costs and for SACs <100MWh, the remaining portion of allocated TUOS costs	●	●	●	●	●	●	●	●	

* The application of capacity or demand based charges is limited by the type of metering installed. Capacity or demand charges are not appropriate for those customers with metering equipment that is only capable of measuring and recording delivered energy volume.

In general, the demand used for the Capacity Charge is based on the authorised

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demand or historical recorded demands. Details of the demand methodology are contained in the Schedule of Network prices.

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APPENDIX 3 – VARIATIONS to PART C of CHAPTER 6 of the RULES

1. Ergon Energy has deviated from Part C of Chapter 6 of the Rules in the following way:
 - a) Include those parts of Part C of the Rules that relate to the operational aspects of network price application and recovery.
 - b) Exclude the operation of the Rules as it relates to the allocation of costs and the calculation of network prices. This exclusion recognises the limitations of the cost allocation and network pricing methodology in the Rules and allows for the formulation of economically efficient network prices based on broader economic principles; and
 - c) Include the remaining aspects of Part C, subject to the variations mentioned in Clause 2(b) below.
2. Ergon Energy has adopted Part C of Chapter 6 of the Rules for connection and access services subject to:
 - a) The **exclusion** from the pricing methodology of the following clauses of the Rules on the basis that they are **replaced by the components of this Pricing Principles Statement**:
 - 6.5.1 Classes of distribution service;
 - 6.5.2 Allocation of aggregate annual revenue requirements to asset categories within classes of network service;
 - 6.5.3 Method of allocation to asset categories;
 - 6.5.4 Allocation of asset category costs to cost pools;
 - 6.5.5 Method of allocation to cost pools;
 - 6.5.6 Cost allocation to Distribution Customers and Embedded Generators;
 - 6.6.1 Embedded Generator prices;
 - 6.6.2 Distribution Customer price;
 - 6.6.3 Prices for Network Users that are both Distribution Customers and Embedded Generators, Subclauses (b) and (c) only; and
 - 6.6.4 Regulation of distribution prices.
 - b) The **exclusion** from the pricing methodology of clauses on the basis that they are **replaced with the following provisions**:
 - 6.6.5 Publication of distribution network prices** is replaced with:

The Rules requires that DNSPs publish network prices for all classes of distribution service at each voltage level. As network prices for EGs are individually determined and are considered commercially sensitive information, these prices will be forwarded directly to the network user and will not be placed in the public domain.

The principles to be applied by Distribution Network Service Providers in relation to the publication of distribution network prices are:

Distribution Network Service Providers in conjunction with the Jurisdictional

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Regulator must publish by 31 May each year:

- 1) a Schedule of Network Tariffs including terms and conditions for standard asset customers (SACs) and the shared network (averaged) component of network prices for CACs where the Schedule of Network Tariffs are to be the maximum price charged; and
- 2) a statement providing details of principles and methods for determining connection charges (this Pricing Principles Statement);

to apply to Distribution customers and Embedded Generators in the following year, commencing 1 July.

Network prices for EGs will not be published but will be supplied directly to the network user.

Price variations other than on an annual basis will be calculated by the Distribution Network Service Provider in accordance with the methodology approved by the Jurisdictional Regulator and implemented at a time to be agreed with the QCA.

6.7.2 Capital contributions, pre-payments and financial guarantees is replaced with:

The Rules requires that DNSPs do not impose capital related charges for assets contributed by network users. One of the difficulties in this requirement is that contributions often relate to many different assets and even part of some assets. It is very difficult for DNSPs to separately identify and account for all contributed assets, particularly when revaluation of assets is required on a periodic basis.

The principles to be applied by DNSPs to the treatment of capital contributions shall recognise that:

- 1) network users should not be charged for assets to which they have contributed;
- 2) DNSP's have a practical difficulty in separately identifying and managing on an on-going basis those assets, or parts of assets, that have been contributed to by individual network users; and
- 3) DNSP's asset base is revalued as a whole at periodic intervals.

Therefore, to meet the intent of the Rules, and to ensure an economic, practical and equitable approach, the following process shall be adopted:

The QCA shall approve the level of capital contributions when determining the DNSPs Revenue Cap for connection and access services.

The capital contribution initial estimation deduction is a once-off reduction in revenue that equates to the net present value of all future network charges for contributed assets. (In this way the assets can be included in the asset base for calculation of ROA and depreciation whilst still recognising the contributions made in accordance with the Rules).

Capital contributions made by Standard Asset Customers are pre-payments of revenue shortfall and therefore will not be individually recognised as the

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customer has paid such capital contribution to access a published network price.

6.8.1 Billing for distribution network services is replaced with:

The Distribution Network Service Provider must bill for connection and access services based on the approved network charges.

Subject to Clause 6.8.1(c), the Distribution Network Service Provider must bill the Market Customer from whom the Distribution customer purchases electricity directly or indirectly for such connection and access services in accordance with clause 6.8.1(a)

If a customer and the Market Customer from whom it purchases electricity agree, the Distribution Network Service Provider may bill the customer directly for connection and access used by that customer in accordance with clause 6.8.1(a)

Distribution Network Service Providers must:

- 1) Calculate TUOS and connection and access charges for all connection points in their distribution network; and
- 2) Pay to Transmission Network Service Providers the TUOS incurred in respect of use of a transmission network at each connection point on the relevant transmission network.

Charges for connection and access services based on metered or agreed or nominated or Authorised kW, kWh, kVA or kVAh for all contestable customers and embedded generators must be calculated by the Distribution Network Service Provider from the data managed by an approved Metering Data Agent.

Charges for connection and access services based on metered kW, kWh, kVA or kVAh for franchise (non-market) customers will be calculated by the Distribution Network Service Provider using data that is consistent with the metering data used by the relevant Retailer in determining energy settlements.

6.8.2 Minimum information to be provided in distribution network service bills is replaced with:

The minimum information to be provided directly to a Rules Participant is:

- 1) the National Metering Identifier (NMI);
- 2) the dates on which the billing period starts and ends;
- 3) the measured quantities, billed quantities, prices and amounts charged for each component of the Distribution customer's.

6.8.4 Obligation to pay is replaced with:

A Market customer, network user, or Embedded Generator must pay distribution service charges properly charged to it and billed in accordance with clause 6.8 by the due date specified in the bill.