



ENERGEN Limited

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**NETWORK PRICING PRINCIPLES STATEMENT
2008-09**

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PREFACE

ENERGEX's 2008-09 Network Pricing Principles Statement (NPPS) sets the basis for how ENERGEN intends to recover the approved annual revenue cap.

ENERGEX is regulated under a revenue cap form of economic regulation for the regulatory period 2005-06 through to 2009-10. Accordingly, the process for converting the annual revenue cap into distribution tariffs is through the setting of a pricing principles statement, and then a pricing submission to the QCA.

ENERGEX released a discussion paper on the development of its network tariff structure in December 2007. Following consultation, ENERGEN has elected to introduce a number of changes in the 2008-09 NPPS compared to the previous NPPS, including:

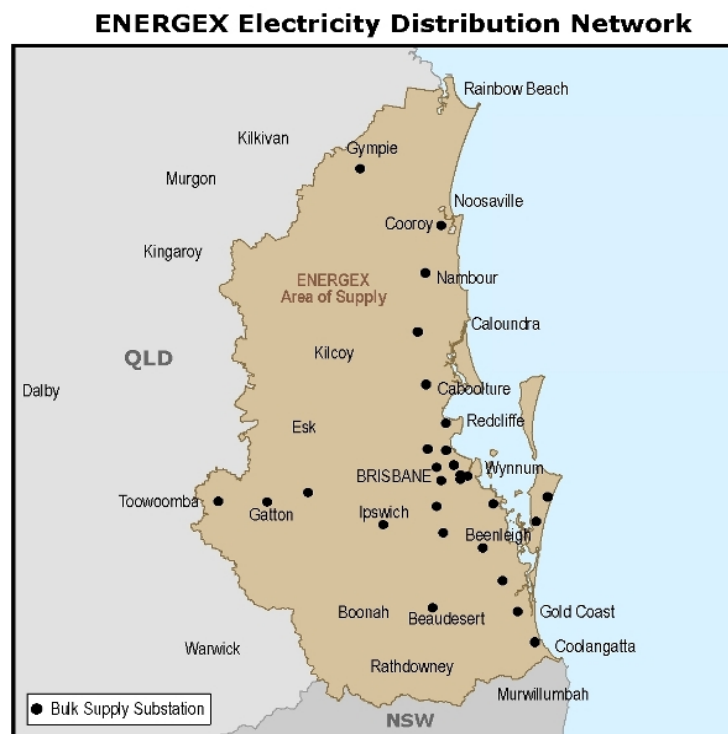
- introduction of new Time of Use (ToU) Volume Price categories for larger customers with interval metering, in addition to existing Business ToU prices (with peak / off peak); and
- changes to streetlight, unmetered supply and night watchman price structures.

Following the release of the Final Decision: Review of Excluded Distribution Services December 2007, Non-DUoS services are now subject to a separate regulatory regime. Accordingly, all references to Non-DUoS services have been removed from this document. Non-DUoS services pricing principles are found in the Excluded Distribution Services Pricing Principles Statement 2008-09, available on the ENERGEN web site.

1. INTRODUCTION

ENERGEX builds, maintains and operates the electricity distribution network for South East Queensland. The distribution network is the network of poles, wires, underground cables, substations and transformers that transports electricity from the high voltage wires operated by Queensland's electricity transmission company, Powerlink, to all 1.3 million homes and businesses in South East Queensland. ENERGEX's assets include more than 50,000km of underground and overhead electricity lines and cables, over half a million power poles, some 43,000 transformers and more than 290,000 street lights. ENERGEX's distribution network stretches from Gympie in the north to Gatton in the west and Coolangatta in the south (see Figure 1), covering around 25,000 square kilometres.

Figure 1: Map of ENERGEX's Electricity Distribution Network



At a high level ENERGEX's distribution network includes:

- **Bulk Supply Substations**

ENERGEX receives electricity from Powerlink Queensland at connection points. The electricity is then distributed at 132,000, 110,000 or 33,000 volts to bulk supply substations.

- **Zone Substations**

ENERGEX's zone substations receive electricity through powerlines or underground cables from the bulk supply substations. They transform this electricity to 11,000 volts for distribution along powerlines or underground cables to distribution substations.

- **Distribution Substations**

ENERGEX's distribution substations receive the 11,000 volt supply from the zone substations and transform it to 240 volts, suitable for residential and commercial use.

- **Transformers**

Transformers are one of the central components in all types of substations. They reduce the voltage of electricity to a lower level suitable for domestic or commercial use.

- **Powerlines/Cables and Poles**

ENERGEX's substations are connected by overhead electricity lines which are supported by electricity poles, and underground cables.

2. **PURPOSE**

In its April 2005 "Final Determination - Regulation of Electricity Distribution" (the Determination), the Queensland Competition Authority (QCA) did not apply Part E of Chapter 6 of the National Electricity Rules (the Rules), and required ENERGEX to submit an annual NPPS. This document is ENERGEX's NPPS for 2008-09.

This NPPS sets out ENERGEX's pricing principles and methodologies that are to be applied when determining network prices in order to recover the revenue cap. For the 2008-09 financial year, ENERGEX will continue to adopt a fully distributed cost model to determine cost reflective prices.

3. **REGULATORY REGIME**

The QCA, as economic regulator, has determined the regulatory arrangements that will apply to prescribed distribution services over the regulatory period and how it will regulate charges for prescribed distribution services and other fees that ENERGEX as an electricity distributor can charge over the regulatory period. The arrangements are specified in the Determination, which is the second determination the QCA has made under the Rules and establishes new regulatory arrangements to apply to ENERGEX for the regulatory period from 1 July 2005 to 30 June 2010.

In 2007, QCA considered an application from ENERGEX for a capital expenditure cost pass-through. QCA accepted ENERGEX's proposed additional capital expenditure as meeting the criteria established in the Determination and approved the pass-through of costs associated with an additional \$720 million of capital expenditure during the current regulatory period. This decision is outlined in "QCA ENERGEX Application for Capital Expenditure Cost Pass-through Final Decision March 2007".

The QCA has decided to continue to regulate ENERGEX's annual aggregate revenue requirement (AARR) using a fixed revenue cap approach. The revenue cap is constructed using a cost linked building block approach where the calculation of the AARR is the sum of:

- the allowed **return on capital**: the return necessary to achieve a fair and reasonable rate of return on the assets necessarily invested in the business;
- the allowed **return of capital**: associated with recouping the capital that has been invested in the business assets over the useful lives of those assets; and
- efficient **operating costs**, including expected efficiency gains.

The regulatory framework has an 'unders and overs' account to allow variations from the allowed annual revenue to be carried forward and adjusted in subsequent years. In addition, it includes pass through mechanisms to manage unforeseen events and provide a degree of flexibility to adjust to changing circumstances within the regulatory period.

The QCA has, within its discretion, elected not to apply Part E of Chapter 6 of the Rules, instead continuing the requirement to submit a NPPS outlining the principles and method for determining individual distribution prices. The NPPS is to be submitted at the commencement of the regulatory period and annually thereafter should it require amendment. Prices reflecting the AARR will be approved only on an annual basis where the prices comply with both the provision of the Rules and the NPPS.

The QCA has also incorporated secondary price controls under the regulatory regime to limit price shocks to customers. In accordance with QCA's ENERGENX Application for Capital Expenditure Cost Pass-through Final Decision [March 2007] ENERGENX is required to apply the side constraint of CPI plus 4.5% to the underlying network prices for contestable customers, however price increases resulting from the pass-through of the costs are not subject to the side constraint.

The QCA has proposed that separate, more 'light-handed' regulatory arrangements will apply to excluded or non-DUoS distribution services (refer Electricity Distribution: Review of Excluded Distribution Services Final Decision, December 2007). The Final Decision explained that at the time of the 2005 Final Determination, the QCA and ENERGENX were of the view that the inclusion of non-DUoS services within the revenue cap would not unduly affect DUoS tariffs as demand for such services had been stable over time. However, with the sale of ENERGENX's retail arm and the introduction of Full Retail Competition, a significant increase in demand for non-DUoS services was anticipated. To prevent subsidisation of DUoS services by non-DUoS services, the QCA considered that non-DUoS services would be more appropriately regulated as excluded services, that is outside of the revenue cap. The QCA therefore deemed that for non-DUoS services, there is a new, prescribed excluded distribution services category. ENERGENX's pricing principles for excluded services are available under a separate document.

This NPPS is designed to continue to fulfil the requirements of the QCA and to communicate the framework that ENERGENX will follow in setting network prices to recover the revenue cap as approved by the QCA during the 2005-10 regulatory period.

4. **NETWORK PRICING PRINCIPLES**

ENERGENX's overall objective in setting network prices is to ensure that the allowable revenue is recovered from network customers in a manner that is consistent with its pricing principles, taking into account that these principles may sometimes conflict with each other.

In addition, ENERGENX is guided by clause 6.1.1 and Schedule 6.7 of Chapter 6 of the Rules.

ENERGENX's current distribution network pricing methodology is developed to achieve the following principles:

- **Regulatory compliance** – network tariffs must comply with the requirements and controls set by the QCA, including achieving the annual revenue target;
- **Free from cross subsidy** – network tariffs should recover costs which are between the 'floor' price, which is the incremental cost of supply, and a 'ceiling' price represented by the stand-alone cost of supply, for a network user, or group of users;
- **Efficient use of the network** – network tariffs should incorporate appropriate signals to network users of their impact on existing and future network capacity and costs;

- **Equity** – network tariffs should be equitable for network users and should reflect the users' utilisation of the existing network and the use of specific dedicated assets;
- **Price stability** – network tariffs should remain stable over time to permit customers to make informed investment decisions;
- **Cost-reflectivity** – network tariffs should reflect the actual cost of service provision to customers; and
- **Simplicity** – network tariffs should be simple and straightforward to apply and readily understood by network users.

5. NETWORK PRICING OBJECTIVES

ENERGEX has adopted the following broad objectives, which are designed to facilitate the application of the principles set out above:

- (1) Network prices are to be consistent with the regulatory regime and any applicable side constraints.
- (2) Network prices should be based on a well-defined and clearly explained methodology.
- (3) Prices are to signal the economic costs of service provision, by:
 - a) being subsidy free (that is, between incremental costs and stand-alone costs);
 - b) having regard to the level of available service capacity;
 - c) signalling the impact of additional usage on future investment costs; and
 - d) encouraging demand management.
- (4) Provided that economic costs are covered, prices should be responsive to the requirements and circumstances of customers in order to:
 - a) discourage uneconomic bypass; and
 - b) allow for negotiation, where appropriate, to better reflect the economic value of specific services.
- (5) The economic signals present in the structure of TUoS charges should be preserved when allocating TUoS charges to distribution network customers, able to interpret those economic signals.

6. TREATMENT OF CAPITAL CONTRIBUTIONS

Capital contributions towards connection investment are sought as prepayment for a revenue shortfall in the case of an uneconomic connection. An uneconomic connection is defined as one where the average distribution prices for the relevant network price category would not be sufficient to recover the full cost of the connection.

Connection costs for ICCs, CACs and Embedded Generators (EGs) are specifically included in the site-specific network charges. Each customer in these classes will incur a network charge inclusive of their site-specific connection costs.

For new SACs wishing to access the standard DUoS tariffs, some level of contribution to the costs of connection may be necessary. ENERGEX determines the level of capital contribution with reference to the following over-arching principles:

- ensuring equitable treatment of existing customers; and
- sending appropriate pricing signals to potential customers that reflect the true cost of network expansion.

ENERGEX's capital contributions policy is based on these principles and can be found in Appendix 2.

7. METHODOLOGY OVERVIEW

ENERGEX has adopted a network pricing cost allocation and network price application methodology broadly consistent with Part E of Chapter 6 of the Rules. The approach adopted by ENERGEN in these pricing principles is to include those parts of Part E of the Rules that relate to the operational aspects of network price application and recovery.

To support the application and recovery of network prices, components of Part E should be retained. Consistent with past practice, ENERGEN is seeking to exclude the operation of the Rules as it relates to the allocation of costs and the calculation of network prices but to include the remaining aspects of Part E. This exclusion recognises the limitations of the cost allocation and network pricing methodology included in the Rules and allows for the formulation of economically efficient network prices based on broader economic principles. Part E of Chapter 6 of the Rules is included in Appendix 3.

ENERGEX will set network prices for 2008-09 using a fully distributed cost model. This approach is as follows:

1. Network Price development should incorporate an analysis of the cost of service provision that includes:
 - definition of the classes of service provided;
 - an allocation of the network costs to service classes;
 - the translation of allocated costs into service prices; and
 - estimates of the stand alone and incremental costs based prices for each service class.
2. Information on allocated TUoS charges should be provided to customers on request.
3. Information on customer class price levels and structures, underlying costs, price derivation methods and rationale and medium term price should be disclosed in order to allow:
 - current and potential customers to understand the basis for prices and to take account of prices in their consumption, investment and location decisions; and
 - interested parties to better assess the range of economic opportunities for meeting customer requirements that may reduce customers' costs and lead to more efficient outcomes.
4. 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 customer requirements and preferences, methods of service provision and costs.
5. Where price strategies lead to proposed price movements or price restructuring that may be expected to impose significant adjustment costs on customers, transitional price options, a phased approach or other measures should be offered to assist in the management of adjustment costs.

ENERGEX has adopted Part E of Chapter 6 of the Rules for connection and access services subject to:

- the exclusion from the pricing methodology of the following clauses of the Rules:
 - 6.13.1 Classes of distribution service;
 - 6.13.2 Allocation of aggregate annual revenue requirements to asset categories within classes of network service;
 - 6.13.3 Method of allocation to asset categories;
 - 6.13.4 Allocation of asset category costs to cost pools;
 - 6.13.5 Method of allocation to cost pools;
 - 6.13.6 Cost allocation to Distribution Customers and EGs;
 - 6.14.1 EG prices;
 - 6.14.2 Distribution Customer price;
 - 6.14.3 Prices for Network Users that are both Distribution Customers and EGs, Subclauses (b) and (c) only; and
 - 6.14.4 Regulation of distribution prices;

on the basis that they are replaced by the components of this Pricing Principles Statement; and

- the exclusion from the pricing methodology of clauses:
 - 6.14.5 Publication of distribution network prices;
 - 6.15.2 Capital contributions, pre-payments and financial guarantees;
 - 6.16.1 Billing for distribution network services;
 - 6.16.2 Minimum information to be provided in distribution network service bills; and
 - 6.16.4 Obligation to pay;

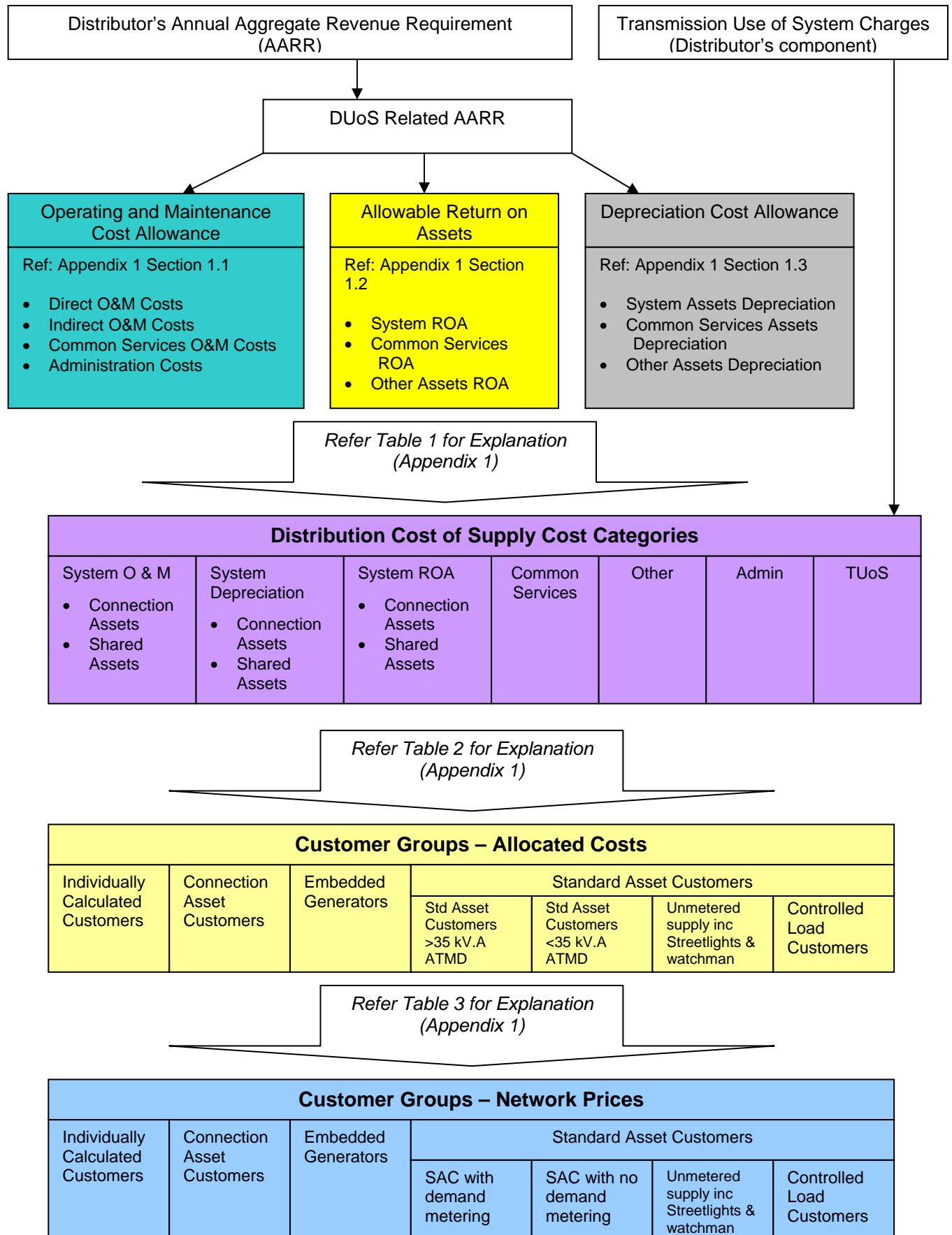
on the basis that they are replaced with the provisions set out in Appendix 4 of this document.

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

- the allocation of the network costs for the provision of the connection and access services to the customers of those services in line with an appropriate methodology; and
- the formulation of efficient network prices that recover those costs.

The network prices developed under this NPPS are cost reflective in that there is a direct relationship between the network price for the service and the costs of delivering that service. This is summarised in Figure 2 and fully explained in Appendix 1.

Figure 2: Network Price Development



8. NETWORK PRICE STRUCTURE

To provide the appropriate economic and cost of supply signals, the network pricing regime distinguishes between different customer groups. ENERGEX has established the current customer groups on the basis of capability to respond to price signals as well as the capacity to make investment and operational decisions that will affect their electricity usage profile. These customer groups are described in the following table.

Table 1: Customer Groups

Customer Group	DUoS		TUoS
	Shared Network	Connection Assets	
ICCs (See Note 1 for description)	Individually calculated based on use of network shared with others based on ATMD	Individually calculated based on the actual assets used	Individually calculated based on demand and electricity at connection point
CACs (See Note 2 for description)	Average shared network costs for group of customers	Individually calculated based on the actual assets used	Allocated on an average of kWh basis
SACs (See Note 3 for description)	Average shared network costs for group of customers	Averaged based on standard connection assets for the Customer Group	Allocated on an average of kWh basis
EGs	Average shared network costs for group of customers	Individually calculated based on actual assets used	Allocated on an average of kWh basis

Note 1: **Individually Calculated Customers (ICCs)** are typically those customers with electricity consumption greater than 40 GW.h per year at a single connection point; or where a customer's circumstances mean that the average shared network charge becomes meaningless or distorted.

Note 2: **Connection Asset Customers (CACs)** typically include the non-ICCs with electricity consumption level greater than 4 GW.h per year at a single connection point; or where a customer has a dedicated supply system with significant connection assets.

Note 3: **Standard Asset Customers (SACs)** are generally those customers with an annual electricity consumption below 4 GW.h per year, whose supply arrangements are consistent across the customer group.

The customers have been classified into groups to provide individual or direct cost of supply signals to those customers who are capable of responding to the signals in the appropriate manner. There is a trade-off between the complexity of individual price calculation and the inefficiencies created through price averaging at the distribution level. A practical limit also arises in the number of site-specific network prices that can feasibly be determined and administered.

Historically, the network prices for ICCs and CACs have been determined on an allocated cost basis. For those ICCs and CACs with network prices that are below the allocated cost, it is intended that the network prices for these customers will be revised and annual adjustments made to align them to the target price levels, but in a manner that is consistent with:

- ensuring that prices are cost reflective;
- complying with the side-constraint on distribution prices as per the "QCA's ENERGEX Application for Capital Expenditure Cost Pass-through Final Decision March 2007"; and
- ensuring that affected ICCs' and CACs' network prices lie within the economic pricing tests of incremental and stand alone costs.

The distributed cost methodology set out in Figure 2 represents a reasonable balance between competing network pricing objectives. Prices calculated on the basis of this methodology lie between the incremental cost of supply and the stand-alone cost of supply.

8.1 Site-Specific and Large Customer Prices

A site-specific price will apply to ICC, CAC and EG customers.

ICC network prices will typically apply to all customers with electricity consumption greater than 40 GW.h per year at a single connection point, or where a customer's circumstances in a pricing zone mean that the average shared network charge becomes meaningless or distorted. ICC prices are based on actual TUoS charges for the relevant transmission connection point, plus charges associated with the customer's shared distribution network utilised for the electricity supply plus connection charges based on connection assets utilised. This provides the greatest cost reflectivity for these customers and is feasible since the number of such customers is relatively small. It is also justified by virtue of the shared distribution network assets being designated specifically to meet the requirements of these customers.

ICC prices for customers with electricity consumption lower than 40 GW.h per year at a single connection point could occur where:

- a customer has a dedicated supply system which is quite different and separate from the remainder of the supply network;
- there are only two or three customers in a supply system making average prices inappropriate; or
- inequitable treatment of otherwise comparable customers arises from the 40 GW.h cut-off.

Selection of these customers will be at ENERGEX's discretion.

CACs' network prices will apply to non-ICCs with electricity consumption greater than 4 GW.h per year at a single connection point. These charges are based on average shared network charges plus site-specific connection charges based on the connection assets utilised, plus average TUoS charges. This provides a significant degree of cost reflectivity for this group of customers while recognising the practical difficulties of calculating individual shared network charges for each customer.

CAC prices for customers with electricity consumption lower than 4 GW.h per year at a single connection point could occur 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 arises from the 4 GW.h per year cut-off.

Selection of these customers will be at ENERGEX's discretion.

EG network prices for connection and access services will be developed on a similar basis to CACs. This is due to the nature of connections, which are typically non-standard and may require additional embedded generator protection system upgrades. If the EG's installation is a net importer of electricity and uses the ENERGEX network to meet its needs when the generator is not running, the appropriate volume charge will apply. The EGs will receive only a single charge for the connection assets regardless of whether they are importing or exporting.

To improve the consistency of network price application across the National Electricity Market, ENERGEX proposes to review the current site-specific network pricing arrangements in relation to multiple network connections. It is intended that a network

price will apply to each connection with the network and that those customers with multiple network connections will, in general, pay multiple network prices. This approach is consistent with the NEMMCO issued NMI Procedure.

As identified in the ENERGETX Development of Network Tariff Structures Discussion Paper 2007, there is a need for continued tariff reform to meet community expectations for cost reflective pricing and improved price signals to customers. Accordingly, from 1 July 2008, for large customers the energy charge will incorporate a peak and off peak element.

8.2 Standard Prices

Standard network prices apply to all remaining network customers. All customers who consume less than 4 GW.h per year are SACs. SACs have averaged connection and shared network costs plus averaged TUoS charges.

The following demand based tariffs apply to customers consuming less than 4 GW.h per year who have meters with demand recording capability at the connection point:

- HV Demand (kW);
- Demand Large (kW);
- Demand Medium (kW); and
- Demand Small (kW).

Customers who do not have demand metering at the connection point will have access to:

- Business Small (0 to 25,000 kW.h pa), non TOU;
- Business Medium, non TOU;
- Business Small (0 to 25,000 kW.h pa) TOU;
- Business Medium TOU;
- Domestic non TOU;
- Load Control 1; and
- Load Control 2.

The applicable network tariff (demand or volume) is based on the metering capability at the connection point.

8.3 Street Lighting Tariffs

ENERGETX has commenced a review of the street lighting cost of supply to ensure street lighting tariffs are cost reflective in light of the pending introduction of contestability from 1 July 2008. Street lighting will have three tariffs: Rate 1, Rate 2 and Rate 3. Within these categories there will be several different subcategories based on lamp type and size. These will reflect the different costs associated with the different types of installation and network connections.

8.4 Unmetered Supply

Unmetered supply tariff is applicable to facilities such as public telephones, traffic signals, and public barbecues which are owned and maintained by the customer. ENERGETX only provides connection to the network for these services.

8.5 Watchman Lights

Watchman lights owned and maintained by ENERGETX will have their own price category.

8.6 Short Term Connection Arrangements

The network price structure for 2008-09 is based on network customers entering long-term connection contracts, which are consistent with the life of the assets utilised. It is recognised that network customers may seek to enter short-term connection arrangements. Under such circumstances it would be reasonable for ENERGEN to have the flexibility to offer the network customer options regarding the contract term, network charges and prudential coverage. For circumstances where a short-term connection arrangement is adopted, ENERGEN may determine network prices on the basis of appropriate accelerated recovery of the costs of the assets employed in providing the connection and access service, subject to ensuring that revenue received does not exceed total costs.

9. **ANNUAL APPROVAL PROCESS**

ENERGEN will submit annually to the QCA a schedule of proposed network prices that are to apply in the following financial year. ENERGEN will demonstrate that the proposed prices comply with the methodology outlined in the NPPS.

The dates for the annual approval process are:

- 31 March ENERGEN submits to QCA the proposed price schedule for the coming financial year;
- 25 May Approval from QCA if satisfied that the proposed prices comply with the NPPS; and
- 31 May ENERGEN publishes price schedule for the coming financial year.

In its annual network prices submission, ENERGEN will provide:

- data and information on how the proposed prices are calculated (including examples);
- a reconciliation of revenue from each customer group with the AARR;
- the proposed schedule of network prices, including terms and conditions, to be published;
- demonstration that the network prices lie between incremental and stand-alone costs; and
- a demonstration that the proposed prices are within the side constraints.

10. **MEDIUM TERM PRICE PATH**

ENERGEX has published its second discussion paper on pricing development, Development of Network Tariff Structures Discussion Paper 2007. The process of tariff structure development is an iterative and evolutionary process. The paper outlined some future pricing options that ENERGEN is exploring such as kV.A based capacity charging¹, Time of Use Capacity Charging, ToU volume based charging, additional Controlled Load Tariff and TUoS allocation. In the longer term, congestion pricing, and zonal pricing may also be considered.

ENERGEN's pricing discussion papers are intended to facilitate a process of interaction between ENERGEN, the regulator and ENERGEN's customers, providing stakeholders the opportunity to participate in the debate on pricing issues.

ENERGEN has considered the feedback received, and the options for possible tariff reforms. In particular, there was strong support for the introduction of kV.A tariffs on a transitional basis, to ensure that customers have time to adjust to the new tariff and where necessary, install power factor correction equipment. The expansion of time of use tariffs was also supported. Feedback on potential changes to tariffs for domestic customers indicated that more consultation is required prior to implementation, particularly around ensuring that the price signal is appropriately reflected in regulated retail tariffs.

Accordingly, for 2008-09, ENERGEN will implement a paper trial to ascertain the appropriateness of introducing kV.A based network charges in the future. This trial will provide an opportunity for customers with demand metering to consider the impact of kV.A tariffs on their specific circumstances. To assist, ENERGEN will provide customers with alternative network demand and capacity charge information. The results of this trial will be evaluated prior to any implementation.

In the medium term, ToU demand, virtual TNI zones for TUoS, wider application of load control prices, zonal pricing and inclining block volume structure are considered worthy of further development in light of the efficiency benefits identified in the discussion paper.

11. **EMBEDDED GENERATORS AVOIDED CHARGES FOR THE LOCATIONAL COMPONENT OF PRESCRIBED TUoS SERVICES (AVOIDED TUoS CHARGES)**

Clause 5.5(h) of the National Electricity Rules requires ENERGEN to calculate 'avoided charges' for the locational component of prescribed TUoS services.

Clause 5.5(i) requires ENERGEN to calculate the amount to be passed through to an EG by:

- a) determining the charges for the locational component that would have been payable by the Distribution Network Service Provider for the relevant financial year if the EG had not injected any electricity at its connection point during that financial year; and
- b) 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).

Clause 5.5 of the Rules is included in Appendix 5 of this NPPS.

¹ Appendix 6 to this NPPS, explains the relationship between kW and kV.A

11.1 Calculation of Avoided TUoS Charges

ENERGEX proposes to use the following methodology to comply with the Rules for EGs who have sought access to ENERGEX's distribution network under Clause 5.5 and who have a generator Connection and Access Agreement with ENERGEX:

- a) determine the amount of electricity sent out by the EG in the relevant billing period (kW.h);
- b) convert this to an equivalent amount of electricity at the Transmission Network Connection Point (TNCP) by adjusting the sent out electricity by the Distribution Loss Factor (DLF) of the EG referred to the TNCP;
- c) add the generation output to the TNCP actual metered data for the period;
- d) recalculate the TUoS as if the generator was not connected;
- e) subtract the actual TUoS payment from the amount calculated in (d); and
- f) credit the value from (e) to the EG account.

Avoided TUoS payments to EGs following the end of the relevant financial year shall be made as a lump sum payment.

11.2 Costs Associated with the Payment of Avoided TUoS Charges

Costs relating to payments to EGs for Avoided TUoS Charges are not part of ENERGEX's AARR. To fund these payments they need to be considered when reviewing the annual TUoS payments and recoveries. In other words the transmission costs (which must be collected from customers) need to be considered as the sum of TUoS payable to the Transmission Network Service Provider and 'Avoided TUoS Charges' payable to EGs.

An estimate of Avoided TUoS Charges for the ensuing financial year can be determined each year when Powerlink's TUoS prices are known. The estimate will be calculated from the forecast EG output and Powerlink TUoS prices for the connection point to which the EG is connected. This estimate can then be factored into TUoS recovery amounts input into the DCOS model to determine appropriate TUoS charges to apply for that financial year.

12. **ADDITIONAL DISTRIBUTION SERVICES**

For 2008-09 following the QCA's Final Decision, 'Electricity Distribution: Review of Excluded Distribution Services', issued in December 2007, distribution services (previously referred to as Non-DUoS services) have been excluded from the overall AARR.

Prices for the excluded distribution services are calculated on a cost reflective basis. ENERGEX's pricing principles and methodology used to establish these prices are detailed in the 'ENERGEX 2008-09 Excluded Distribution Services Pricing Principles Statement'.

Appendix 1: Cost Allocation Process

1. COST ALLOCATION PROCESS

The revenue cap as determined by the QCA is based on a building block approach, which includes each of the regulated cost components, namely:

- operating and maintenance (O&M) costs;
- depreciation; and
- a reasonable rate of return (WACC) on the depreciated value of the assets.

The first stage of the network price determination process is to allocate or assign the network costs to the customer groups in the most efficient and cost reflective way. That is, costs are allocated on a causal basis. This section sets out the cost allocation process utilised by ENERGEX in the determination of network prices.

1.1 Operating and Maintenance (O&M) Costs

The QCA has determined an overall efficient operating cost target for ENERGEX as part of the regulatory review process. To progress through the cost allocation process, this overall target is separated into a number of cost groups that are consistent in relation to drivers. These O&M cost groups are:

- a) Direct O&M Costs – the directly attributable costs associated with the provision of network connection and distribution services;
- b) Indirect O&M Costs – engineering and supervisory overheads associated with network management and the provision of connection and distribution services;
- c) Common Service Costs – the directly attributable operating and maintenance cost associated with common service activities as described in the Rules; and
- d) Administration Costs – those corporate overheads including CEO, IT&T, HR and Customer Services which are not directly linked to the operation and maintenance of the network, but which are associated with network service delivery.

Historical O&M costs are the basis for allocating to these cost groups.

1.1.1 Direct O&M Costs

The Direct O&M Costs are further segregated into voltage level cost groups based where possible on the historical direct operating and maintenance expenditure on the asset classes. Where historical data is not available, the budget forecast and replacement cost of assets are used to allocate Direct O&M Costs.

The Distribution Cost of Supply (DCOS) model is used to allocate the costs associated with the operation and maintenance of the asset classes to the users of the asset class. For example, the customers taking supply at the 11kV level will be allocated a proportion of all of the upstream costs (33kV, 110kV, etc) while those taking supply at the 110kV level 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).

The voltage level direct O&M cost groups are:

- 110/132kV;
- 33kV Bus;
- 33kV Line;
- 11kV Bus;

- 11kV Line;
- low voltage;
- services (low voltage only);
- meters; and
- relays.

1.1.2 Indirect O&M Costs

The Indirect O&M Costs are allocated to the above listed voltage level cost groups in proportion to the allocated direct costs. This allocation is made on the basis that the engineering and supervisory costs are incurred proportionally to the direct O&M costs.

1.1.3 Common Service Costs

Common Service Costs are costs associated with those system assets that benefit the system as a whole and are not directly related to any single customer or group of customers. Assets included in this category are reactive plant, load control, control centres and communications.

1.1.4 Administration Costs

The Administration Costs are the summation of the non-system based costs which include corporate overheads and customer services. These costs are treated consistently as a group as it is impractical to manage a cost allocation stream for each of the specific components, for example, CEO, IT&T and HR. In addition the cost drivers for this set of costs are consistent along with the allocation methodology.

1.2 Return on Assets

The Return on Assets (ROA) component of the revenue cap (representing a reasonable rate of return) can be separated into three separate cost groups on the basis of asset type. These cost groups are:

- a) System ROA – the return on those system assets employed in the provision of network connection and distribution services to customers (including any applicable tax);
- b) Common Services ROA – the return on those system assets associated with the provision of common services; and
- c) Other ROA – the return on non-system assets (for example, fleet, computers and buildings) and working capital, which are employed to provide regulated services to customers.

ROA costs are allocated to each cost group in proportion to the value of assets.

1.3 Depreciation

The depreciation allowance can also be separated into the three cost groups as with the ROA allowance, as follows:

- a) System Assets Depreciation - the depreciation of those assets employed for the provision of network connection and distribution services to customers;
- b) Common Services Assets Depreciation – the depreciation of those assets associated with the provision of Common Services activities; and

- c) Other Assets Depreciation – the depreciation of the non-system assets (for example fleet, computers and buildings) which are employed to provide regulated services to customers.

Depreciation costs are allocated to each cost group in proportion to the value of assets.

1.4 DCOS Cost Categories

Table 1 below sets out the translation of these cost groups which relate to the components of the revenue cap into DCOS cost categories that are homogeneous in relation to cause and allocation approach. Table 2 in the next section sets out the allocators that are used to distribute these costs across the relevant customer groups.

Table 1 – Cost Groups to DCOS Cost Categories

Revenue Cap Components ↓	Cost Groups ↓	DCOS Cost Categories						
		System O&M	System Depreciation	System ROA	Common Services	Admin	Other	TUoS
O&M Section 1.1	O&M Direct	✓						
	O&M Indirect	✓						
	O&M Common Services				✓			
	O&M Administration					✓		
ROA Section 1.2	ROA on System Assets			✓				
	ROA on Common Services				✓			
	ROA on Other Assets						✓	
Depreciation Section 1.3	System Asset Depreciation		✓					
	Common Services Asset Depreciation				✓			
	Other Assets Depreciation						✓	
TUoS	Transmission Use of System Charges							✓

1.5 Allocation of DCOS Cost Categories to Customer Classes

There are four general groups of network customers to which network costs are allocated. These groups are:

- a) ICCs;
- b) CACs;
- c) SACs; and
- d) EGs.

The SAC group includes those customers who remain on a Notified Retail Tariff.

The purpose of the cost allocation process is to develop a 'cost for the provision of network connection and access services' for each of these customer groups based on appropriate cost drivers and/or cost allocations.

1.5.1 **Cost Allocations**

There are a range of cost allocators that can be used in a DCOS model such as that used by ENERGEN. The selection of the appropriate allocator is based on the ability of that allocator to reflect the fundamental cost driver. The range of possible allocators includes:

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

ENERGEN has adopted the following allocators in the cost allocation model:

- number of customers;
- anytime energy; and
- anytime maximum demand.

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

- a) number of customers – this allocator is appropriate for those costs that are dependent upon or driven by the number of connected customers. ENERGEN has a number of costs that are customer number based. Indeed a significant proportion of the overhead costs of the business are driven by the number of staff and systems required to serve the customer base;
- b) energy – this has been used as an allocator for those costs that are related to the size of the customer but not specifically the demand of that customer on the network. Those costs that cannot be directly related to a product or service are recovered through the use of energy prices (for example, market fees, and ancillary services fees); and
- c) anytime maximum demand (ATMD) – this method of allocation has been 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. Individual demands throughout the network combine to form an overall coincident system peak demand, however this demand is more relevant to transmission network capacity than distribution. Therefore, anytime demand

which reflects the demands of various customer groups in different parts of the network is a reasonable driver.

Whilst the ideal cost allocation mechanism would be based on a real-time model which replicates these network location-specific demands, such an approach is not achievable at present. Anytime maximum demand provides a simple and reasonable basis for apportioning system usage related costs given the present availability of data. It reflects the fact that demand is the primary driver of shared network costs whilst overcoming the limitations that other allocators have in recognising the variations across the network.

1.5.2 Implemented Cost Allocations

Table 2 below sets out the DCOS cost categories, the applicable class of distribution service (consistent with the Rules), the cost driver and the cost allocation methodology adopted in accordance with the previously established principles. Within each of the groups of network customers, there are a number of distribution network users with a range of network prices. The allocation of costs within a group to the network customers is on the same basis as for the general allocation of costs to the groups as described in Table 2.

Table 2 – Allocation of Costs to User Groups

DCOS Cost Category	Rules Service Class	Cost Driver	Cost Allocation Methodology
System O&M	Exit Service, Entry Service, and Distribution Use of System Service	<ul style="list-style-type: none"> • Connection Capacities • Demand on relevant parts of the network • Number of connections 	Costs apportioned to asset categories (asset groups at voltage level) on the basis of direct costs (O&M Direct). O&M Indirect is apportioned consistent with O&M Direct. The costs are then allocated to customer groups on the basis of the use of those assets through direct allocation for connection assets and ATMD for shared assets.
System Depreciation	Exit Service, Entry Service, and Distribution Use of System Service	<ul style="list-style-type: none"> • Connection Capacities • Demand on relevant parts of the network • Number of connections 	Costs apportioned to assets (in DCOS categories) by voltage level proportional to the replacement costs. Costs are then allocated to customer groups on the basis of the use of those assets through direct allocation for connection assets and ATMD for shared assets.
System ROA	Exit Service, Entry Service, and Distribution Use of System Service	<ul style="list-style-type: none"> • Connection Capacities • Demand on relevant parts of the network • Number of connections 	Costs apportioned to assets (in DCOS categories) by voltage level proportional to the replacement costs. Costs are then allocated to customer groups on the basis of the use of those assets through direct allocation for connection assets and ATMD for shared assets.



DCOS Cost Category	Rules Service Class	Cost Driver	Cost Allocation Methodology
Common Services	Common Services	<ul style="list-style-type: none"> • System control and stability • No unique cost driver 	<p>Costs allocated to all customers using energy as the allocator.</p>
Admin	Exit Service, Entry Service, and Distribution Use of System Service	<ul style="list-style-type: none"> • Number of customers connected • Service requirements of customers 	<p>These costs are associated with the number of connected customers and their expectations/service requirements. A hybrid allocation of a percentage of costs per customer (75%) and a percentage of costs on a c/kW.h (25%) is adopted. These weights reflect that the number of customers is the primary driver of the Administration costs.</p> <p>EGs will be allocated a fixed dollar (\$) cost depending on size and type of connection. These costs reflect the additional operational service required by EGs.</p>
Other	Exit Service, Entry Service, and Distribution Use of System Service	<ul style="list-style-type: none"> • Number of customers connected • Service requirements of customers 	<p>These costs are associated with the number of connected customers and their expectations/service requirements. A hybrid allocation of a percentage of costs per customer (75%) and a percentage of costs on a c/kW.h (25%) is adopted. These weights reflect that the number of customers is the primary driver of the other costs.</p> <p>EGs will be allocated a fixed dollar (\$) cost depending on size and type of connection. These costs reflect the additional operational service required by EGs.</p>
Capital Contributions	Exit Service, Entry Service, and Distribution Use of System Service	<ul style="list-style-type: none"> • Number of customers connected • Service requirements of customers 	<p>These costs are associated with the number of connected customers and their expectations/service requirements. A hybrid allocation of a percentage of costs per SAC customer (75%) and a percentage of costs on a c/kW.h (25%) is adopted.</p>
TUoS	Transmission Use of System Service	<ul style="list-style-type: none"> • Allocation to network customers as per Rules. 	<p>For ICCs, the TUoS is passed through on a reflective basis proportional to the Nominated Demand of the Customer and their electricity consumption.</p> <p>For all remaining customers, TUoS is allocated to customers based on customers' electricity consumption.</p>

1.5.3 Cost Based Network Prices

Table 3 below represents the conversion of the DCOS Cost Categories to the cost-based network price components.

Table 3 – Conversion of DCOS Cost Categories to Prices

DCOS Cost Category		Network Price Components		
		Fixed or Service Availability Charge (\$/period)	Volume Charge * (c/kW.h)	Capacity / Demand Charge (\$/kW)
System O&M	Connection Assets	✓		
	Shared Assets		✓#	✓
System Depreciation	Connection Assets	✓		
	Shared Assets		✓#	✓
System ROA	Connection Assets	✓		
	Shared Assets		✓#	✓
Common Services			✓	
Administration		✓	✓	✓
Other		✓	✓	✓
TUoS	ICC	✓	✓	✓
	CAC	✓	✓	✓
	SAC	✓	✓	✓**
	Streetlight and other Unmetered Supply	✓	✓	
	Controlled Load	✓	✓	

Table Notes

Applicable to customers without demand metering.

* The structure of the volume charge can incorporate either a flat rate for all energy or a Time of Use volume charge which has different rates according to the time and day when the consumption occurs.

** For customers without demand metering, this component will be converted and added to the volume charge.

Network prices developed using this process are categorised as cost-based. By definition these cost-based prices are economically efficient in that they lie between the boundaries established by the stand-alone and incremental costs.

As a result of the cost allocation methodology described in this document, 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. As shown in Table 3, 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 any customer above the incremental cost of supply (the economic cost floor).

In the case of smaller network customers connected at the distribution level (generally 11kV and below), the allocated cost of supply will be well below stand-

alone costs of supply. The stand-alone costs for a small user would include costs associated with dedicated upstream infrastructure. These costs are shared between many customers in the case of the fully allocated model hence the allocated cost model should always lie below the stand-alone cost.

For larger network customers connected at the sub-transmission level (33kV and above), the allocated cost model includes a site-specific component of supply network costs. ICC 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-user 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 CACs take into account the specific connection costs as well as an allocation of the upstream shared network costs. Consistent with the distribution level network customer, this allocation of upstream shared network costs will result in individual network prices being less than a stand-alone ceiling cost for the CAC group.

1.6 **Development of Economically Efficient Network Prices**

The second process in the development of network prices is the calculation of actual network prices taking into account the following factors:

- a) allocated costs;
- b) network cost drivers;
- c) network use and utilisation signals;
- d) economic efficiency of network prices;
- e) income and expenditure alignment; and
- f) network price stability.

Consistent with the Rules, the network prices proposed by ENERGETEX will be comprised of a number of components, each selected and structured to provide signals to customers about the efficient use of the network and the impact of future network capacity and costs.

The price structure and the proportioning of charge components have been developed to achieve the objectives listed previously. In developing the network prices, ENERGETEX has sought to have the price components signal the impact that the end users will have on the network whilst managing the demand and volume variance risk, minimising boundary issues between and within customer classes and avoiding any signals that may result in perverse outcomes.

As discussed previously, the fixed or standing-charge components adopted are intended to reflect the incremental costs that arise from the connection and management of the customer. This sends a clear signal about the economic value of the dedicated connection and provides a stable price and income regardless of the usage of the network. Network usage signals are provided by other price components.

Shared network costs are recovered through capacity and demand charge components from all customers with demand metering. For non-demand metered customers, these charges are recovered through the volume charge. These together provide the economic signals to the customers on the use of the shared network.

A monthly maximum demand charge is levied on the basis that network 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 aggregated network usage during peak times. Co-incident peak demand is, therefore, the

driving factor behind system augmentation. In this context, network 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 network user's contribution to co-incident peak demand, the maximum demands of those network 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 network customers who make maximum demands on the system at infrequent intervals. These customers would generally possess a low load factor.

The load factor is the ratio of average hourly consumption and peak demand over a period of time and measures the variability of a network user's consumption. A low ratio, for instance less than 0.2, suggests a variable consumption pattern while those closer to unity identify more constant electricity usage. All else being equal, a network user with a low load factor would pay considerably less than a high load factor user who has an identical maximum demand.

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 network customers that they can reduce their network charges by reducing the variability of their consumption, as this lower peak demand reduces the pressure that they place on the network.

The demand to be used for the calculation of the capacity charge is either the contracted demand, the annual maximum demand in the most recent 12-month period prior to the setting of prices or a demand agreed between ENERGEN and the network user.

Capacity charges are designed to recover shared network costs and to reflect the long-run marginal cost of network capacity augmentation, while demand charges are designed to provide a short-run marginal cost signal.

Volume charges have been adopted to recover those costs that are not specifically related to demand for demand metered customers but includes demand related charges for non-demand metered customers. Non-demand costs include costs such as administration overheads, and common service costs. Volume charges are also used to recover any residual allocated costs after the capacity and demand charges have been calculated. Volume charges can be structured either as a flat anytime energy charge or a time of use energy charge. By using a time of use structure, a volume charge can provide a small price signal that encourages efficient use of the network. To improve network efficiency and price signal clarity, alternative volume structures will be utilised. The volume charge applies to the electricity (kW.h) metered at the network user installation.

The pass through of TUoS charges has been the subject of significant discussion in the National Electricity Market. Consistent with the intention that those end users able to respond to the TUoS signal receive the signal, ENERGEN's network price calculation process passes through TUoS as cost reflectively as possible.

Consistent with the allocation of shared network costs, these TUoS components are allocated to individual ICCs on the basis of ATMD and anytime energy and recovered in prices by means of: a fixed charge; a capacity charge; a common service charge; a general charge; and a volume charge reflective of the average transmission connection point charges for the ENERGEN network.

For CACs and SACs, TUoS is allocated to the group on the basis of energy. For CACs, TUoS is recovered via prices by means of a fixed charge, a capacity charge and a volume charge. For SACs with demand meter data available, TUoS is recovered via a fixed,

demand and volume charge basis. For SACs with no demand meter data available, TUoS is recovered only on the basis of fixed and volume charges.

The network price components adopted by ENERGEX for each of the network user groups are detailed in Table 4 below.

Table 4 – Network Price Components

Network Price Component	Description	Customer Classes to which Network Price Component is applicable						
		ICC	CAC	EG	SAC			
					With Demand Meter Data	With NO Demand Meter Data	S/L	Control Load
Fixed or Service Availability Charge (\$/period)	<u>DUoS</u> Reflective of the costs associated with the connection assets (entry and exit services) and Network User management services	✓	✓	✓	✓	✓	✓	✓
	<u>TUoS</u> A proportion of the allocated TUoS costs	✓	✓		✓	✓	✓	✓
*# Capacity Charge (\$/kW/period)	<u>DUoS</u> Reflective of the network capacity required by the Network User on a long-term basis and levied on the basis of a contracted demand	✓	✓	✓**				
	<u>TUoS</u> A proportion of the allocated TUoS costs	✓	✓					
Common Service Charge (\$/period)	<u>TUoS only</u> A proportion of the allocated TUoS costs	✓						
*Monthly Maximum Demand Charge (\$/kW/period)	<u>DUoS</u> Reflective of the costs of network availability and limitations	✓	✓	✓**	✓			
	<u>TUoS</u> A proportion of the allocated TUoS costs				✓			
Volume Charge*** (¢/kW.h)	<u>DUoS</u> Recovery of costs not directly allocated with network drivers. The charge also includes costs that are proportional to the size of the customer, such as customer management.	✓	✓	✓**	✓	✓	✓	✓
	<u>TUoS</u> A proportion of the allocated TUoS costs	✓	✓	✓**	✓	✓	✓	✓

* The application of capacity or demand-based charges (either authorised or actual) is limited by the type of metering installed. Demand charges are not appropriate for those customers with metering equipment only capable of measuring and recording delivered electricity volume.

** These rates apply to EGs only when they are importing electricity to their site (that is as a load customer).

*** Volume charge may be either or a combination of Flat or ToU.

In general, the Capacity Charge is based on historical recorded demands. The details of the nominated demand calculation methodology are included in the relevant network price schedule.

1.7 Variations from Allocated Cost-Based Prices

ENERGEN currently develops and applies network prices based on the distributed cost model. The network pricing methodology applied to each of those groups has precluded any possible bypass challenge on the basis that the network price is efficient and an alternative electricity service can not be sourced at a lower economic value.

Consistent with Objective 5 from Section 5, ENERGEN 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 as an economic bypass opportunity exists or an alternative electricity service could be utilised.

Appendix 2: ENERGEN's Capital Contribution Policy

1. TREATMENT OF CAPITAL CONTRIBUTIONS

This is ENERGEN's policy for seeking capital contributions from new customers connecting to the electricity network and is primarily targeted at SACs. The policy is consistent with the principles outlined in ENERGEN's NPPS, specifically, that the capital contributions policy:

- ensures the equitable treatment of existing customers; and
- sends appropriate pricing signals to potential customers that reflect the true cost of network expansion.

The policy was developed following discussions with the QCA.

1.1 What are Capital Contributions

Capital contributions are made by customers or an individual customer to the network operator where the network operator considers that it would not be able to fully recover the costs of delivering services to that customer through annual prices. When this assessment is made, a capital contribution towards connection investment is sought as a prepayment for the expected revenue shortfall in the case of an uneconomic connection.

An uneconomic connection is defined as one where the average distribution prices for the relevant network price category would not be sufficient to recover the full cost of the connection. Connection costs for ICCs, CACs and EGs are specifically included in the site-specific network charges. Each customer in these classes will incur a network charge inclusive of their site-specific connection costs.

1.2 Principles for Setting Capital Contribution

For new SAC customers wishing to access the standard DUoS tariffs, some level of contribution to the costs of connection may be necessary. The level of capital contributions is determined by reference to the following objectives:

- to meet the economic efficiency objective, capital contributions should only cover any shortfall between the present value of additional distribution charges expected to be paid by the new customer over the life of the assets and the incremental cost of connecting that customer. This approach ensures that existing customers are no worse off following the connection of a new user because the expected network revenue from the new customer (in the form of additional charges and/or capital contributions) will cover the incremental cost of supply; and
- to meet the equity objective, it is reasonable to expect each customer, in addition to their incremental costs of connection to make some contribution to shared assets.²

The test to be applied to new SAC customer connections incorporates both economic efficiency and equity components. The concepts of economic efficiency and equity as related to capital contributions are outlined in the following sub-sections.

1.2.1 Economic Efficiency

The economic efficiency test is based on the principle that existing customers will be no worse-off following the introduction of a new user, that is, the expected network revenue from the new user at least covers the incremental cost of supply.

Operationally, therefore, if the present value of future DUoS revenue from the new user is greater than the incremental costs of supplying distribution services to the

² QCA (April 2005), "Final Determination – Regulation of Electricity Distribution", Page 186.

new user, then all existing customers will be better off. If the expected revenues are insufficient to cover these incremental costs (and the entrant wants to access standard DUoS tariffs), then a contribution will be required. If no contribution was sought from this customer, and they were allowed to access standard tariffs, average DUoS charges for all customers on these tariffs would increase. Therefore, the minimum capital contribution will be calculated by deducting the present value of expected future DUoS revenues from total incremental cost.

1.2.2 Equity

Equity considerations suggest that new customers should, in addition to meeting incremental costs, contribute to the costs of the existing shared network. These costs, which in economic terms are defined as joint production costs³, do not have a separable cost function and therefore cannot be specifically determined by varying the relative proportions of the services provided. Consequently, there is no objective way of attributing joint production costs to the new distribution service. Any method used to allocate or attribute shared network costs to new customers will result in one of a broad range of possible outcomes. The acceptable range of outcomes is constrained by the incremental/stand-alone cost rule that is explicitly employed in ENERGEX's network pricing principles. Nevertheless, for a new customer this range could be considerable.

In determining a reasonable level of shared network contribution for a new connection, ENERGEX has had regard to the range of contributions made by existing customers. Contributions to shared network costs will vary significantly across the network. However, it is proposed that a standard contribution of 10% of expected DUoS revenues will be applied when determining capital contribution levels for SAC customers because this approximates the minimum contribution to shared network costs that is currently made by SAC customers.

The following section outlines the approach that ENERGEX has employed in determining the level of contribution new customers are required to make from 1 July 2005.

2. METHOD OF CALCULATING CAPITAL CONTRIBUTIONS

The method used to calculate capital contributions is based on the following:

- forecast DUoS revenue based on DUoS charges applicable to the relevant customer class. The DUoS rates to be used in the calculation would be the rates as published annually in ENERGEX's Network Price Submission to the QCA;
- a discount rate based on ENERGEX's approved regulatory WACC converted to pre-tax terms using the estimated average effective tax rate for the regulatory period;
- twenty year discount periods for both domestic and commercial customers as this represents a reasonable expectation with regard to the average life of the assets and the period of time before customers are expected to seek capacity enhancements;
- a 10% reduction in the discounted DUoS charges to account for the contribution to the shared network;
- calculating the incremental costs of connection will include two elements (both of which are calculated before ENERGEX applies GST);
- the actual cost of connection (the capital cost of the network connection assets including overhead service and metering equipment); and

³ Reflecting economies of scope.

- additional costs, both capital and operating, incurred in the shared (upstream) network as a direct result of the new connection.

For most SAC customers, identifying specific upstream network costs is extremely difficult and is generally expected to be immaterial. However, where they can be clearly identified and are considered material, they will be included in the calculation of total incremental costs.

Calculation of a new customer's capital contribution level can be expressed mathematically as follows:

$$CC = ICCS + ICSN - [IR(n=20) - SNC(10\%)]$$

Where:

CC	=	Capital Contribution
ICCS	=	Customer specific incremental costs
ICSN	=	Incremental costs in the upstream (shared) network directly attributable to the new connection
IR(n=20)	=	Present value of a 20 year revenue stream directly attributable to the new connection
SNC(10%)	=	A 10% attribution of Incremental revenue (IR(n=20)) to the costs of the existing shared network.

3. **SHARING CAPITAL CONTRIBUTIONS**

ENERGEX's policy for sharing capital contributions as additional customers connect to a network extension that was initially subject to a capital contribution by the original connecting customer is outlined in this section.

3.1 **Method of Sharing**

Past contributions are not refundable. However, past contributions may be shared with additional customers – that is, the amounts contributed by additional customers become the basis of any payment to the customer who paid the initial contribution.

ENERGEX's policies relating to the sharing of capital contributions are outlined below:

- initial contribution levels are reduced to zero over a period of five years (20% reduction annually from date supply is available). The impracticality of administering such a scheme on an indefinite basis requires that some limit be placed on the period over which capital contributions can attract refunds from future customers.
IPART (April 2002) found that most interested parties considered a period in the range of 5-7 years reasonable. While IPART decided on a 7-year period, it restricted the application of capital contributions to rural and large load customers. ENERGEX employs no such restriction on the application of capital contribution and hence a shorter period is applicable given the greater turnover of smaller urban properties;
- subsequent contributions to the initial extension should be calculated proportionate to customer size based on forecast DUoS revenue from DUoS charges applicable to the relevant customer class;
- no sharing of contributions is permitted for additional customers connected to an extension supplied under a Rural Subsidy Scheme; and
- amounts less than \$100 will not be refunded.

4. IN-KIND CAPITAL CONTRIBUTIONS

In some cases customers connecting to ENERGEN's network will provide In Kind capital contributions (non-cash). This section outlines ENERGEN's treatment of In Kind capital contributions.

4.1 Individual Customers

For an individual customer connection providing In Kind capital contributions (non-cash) the following approach applies:

- where the total project cost (as determined by ENERGEN) is less than the incremental revenue threshold, ENERGEN will repay the total cost to the customer; and
- where the total project cost (as determined by ENERGEN) is greater than the incremental revenue threshold, an amount equal to the threshold will be repaid to the customer with the residual recorded as an In Kind capital contribution to be netted-off against the allowed network revenue limit.

4.2 New Developments

ENERGEN also receives In Kind capital contributions from developers for multiple connections associated with new developments.

4.2.1 Background

In the late 1980s, SEQEB (predecessor to ENERGEN) established a policy that allowed for the electricity reticulation of subdivisions by developers through the use of an agreement and approved consultants and contractors. This policy was developed and deployed to reduce the delays in construction of residential type subdivisions. Rural and commercial and industrial subdivisions are also covered by the same general principles.

This arrangement has been in place since that time with some minor modifications to allow for the impacts of the Trade Practices Act and during the late 1990s for the changing regulatory arrangements.

4.2.2 Historical Approach

The general approach employed by ENERGEN to calculate capital contributions relating to the supply of electricity infrastructure to subdivisions comprising two or more lots was as follows:

- ENERGEN prepared an estimate of the costs of the project based on the consultant's design and materials lists. This estimate used standard cost models for subdivision works;
- ENERGEN supplied transformers and cables as well as any overhead materials up to a maximum value per lot. All other materials, services and labour used during the design and reticulation of the estate were provided by the developer;
- at completion and energisation of the subdivision, the estimate of costs plus the additional costs of ENERGEN's management of the subdivision agreement and works were capitalised;
- the value of the developer's contribution, being the difference between the estimated costs of the project and ENERGEN's associated materials and project costs, was treated as a Capital Contribution In Kind. This amount was debited from the Capital Account and credited to the Capital Contribution

Account. In this way, the value of the contributed assets was treated as a Capital Contribution, consistent with the regulatory regime and the assets were included in the capital accounts at their equivalent construction value; and

- in determining annual DUoS charges, the value of the Capital Contributions In Kind for subdivision projects was netted off the total revenue limit and was allocated to the appropriate cost categories as set out in Appendix 1 of the NPPS. All Capital Contributions In Kind arising from residential subdivisions were allocated to the <35 kV.A SAC category.

4.2.3 Basis for Phasing in the New Policy

ENERGEX's previous capital contributions policy had been in place since the late 1980s. Industry participants, particularly the development industry, were familiar with ENERGETEX's policy, practices and processes. As matter of due process, ENERGETEX considered it appropriate that all stakeholders be thoroughly consulted regarding the introduction of any new capital contributions policy (which is outlined in section 4.2.4 below). ENERGETEX is keeping the QCA informed about the content and progress of the consultation process.

The development industry operates under investment decision rules with lead times from project conception to completion of approximately two to three years – depending on the scale of the development. Accordingly, ENERGETEX considered that for equity reasons a phased introduction of the changes to the previous capital contributions policy ensures that:

- market based returns from approved developments are not negatively impacted by the change;
- the industry is provided with sufficient time to understand the changes, and adequately incorporate the impact of the change within investment decision making frameworks and processes; and
- market participants are allowed to adjust to the policy change, which would result in the efficient allocation of costs and risks in the market place.

To practically comply with the proposed capital contributions policy ENERGETEX is changing substantial elements of its policies, practices and processes, and is likely to need to introduce several new processes and systems to ensure full compliance with the policy. To successfully make such changes, which will involve extensive stakeholder consultation, ENERGETEX will require the time set out in section 4.2.5.

4.2.4 Amended Approach for New Developments – Introduced from 1 July 2006

It is expected that developers will be required to pay for all costs (inside the development and upstream augmentations) associated with supplying electricity to lots within the development. From July 2006, ENERGETEX's capital contributions policy for In Kind contributions from developments has incorporated:

- the phased introduction of contestability for the procurement of major electricity reticulation materials by developers supported by the introduction of an ENERGETEX approved standard for design, specification and quality levels for the procurement of major electricity reticulation materials purchased by developers and their sub-contractors;
- the phased removal of the contributed value per lot for electricity reticulation materials supplied by ENERGETEX to developers from July 2006 to July 2009;

- as part of the phased removal of the contributed value per lot, developers will have a maximum of 12 months from the date of the execution of the Subdivision Supply Agreement to complete the installation of the electricity reticulation assets supplied. Where the developer has not installed the electricity reticulation materials supplied by ENERGEX within the 12 month period, ENERGEX will re-assess the contributed value per lot as per the transitional arrangement that applies for the relevant financial year as per Table 1;
- ENERGEX will contribute to the costs for the following works:
 - feeder and shared network augmentation outside of the development that has specifically been required by ENERGEX that is above what is required to supply the development (for example tie cables for reliability purposes); and/or
 - backbone network augmentation within the development requested by ENERGEX that is above that required to supply the development;
- ENERGEX's contribution to a development will not exceed either:
 - the total costs of the additional works requested by ENERGEX; or
 - the contribution shown in Table 1 item no 4 below; and
- the developer will be responsible for the full cost required to service the development.

4.2.5 Schedule for Introduction

As set out in section 4.2.4, ENERGEX is implementing a phased introduction of the new capital contribution policy for new developments. Table 1 outlines the broad timetable for introducing the policy changes.

Table 1 – Schedule for Implementation of New Capital Contributions Policy for Subdivisions

No	Key project	July 2005	July 2006	July 2007	July 2008	July 2009
1	Development of specific details on the new Capital Contributions Policy in consultation with relevant stakeholders including Queensland Government, Urban Development Institute of Australia, ACCC, QCA, and material suppliers	Commencement of Consultation				
2	Industry consultation on draft new capital contributions policy		Commencement of Consultation			
3	Publication of final capital contributions policy		Completed by June 2007			

No	Key project	July 2005	July 2006	July 2007	July 2008	July 2009
4	Phasing out of ENERGEX's current practice of providing electricity reticulation assets		75% of X\$ ⁴ per lot	50% of \$X per lot	25% of \$X per lot	0% of \$X per lot
5	ENERGEX will contribute to the costs for the following works: <ul style="list-style-type: none"> • feeder and shared network augmentation outside of the development that has specifically been required by ENERGEX that is above what is required to supply the development (eg tie cables for reliability purpose); and/or • backbone network augmentation within the development requested by ENERGEX that is above that required to supply the development 		ENERGEX's contribution to a development will not exceed either: <ol style="list-style-type: none"> a) the total costs of the additional works requested by ENERGEX; or b) the contribution listed in this Table 1 under item no 4 (above) 			
6	Introduction of contestability for procurement of major electricity reticulation materials by developers		Industry consulted from July 2006	Completed by June 2007 Commence from July 2007	Annually reviewed and amended to accommodate gradual phase out of ENERGEX supplying electricity reticulation assets	
7	Establishing design, specifications and quality standards for key network electricity reticulation materials and assets	Developed, industry consulted from November 2005	Draft by June 2006	Completed by June 2007 Commence from July 2007	Annually reviewed and amended to accommodate gradual phase out of ENERGEX supplying electricity reticulation assets	

ENERGEX would like to highlight the change to the level of contribution that ENERGEX will make to works involved with subdivision developments. This revision has been included to ensure the Capital Contribution arrangement complies with the regulatory regime.

⁴ The contributed value for major electricity reticulation materials (cables and padmounts etc) supplied by ENERGEX to new developments has been provided on a confidential basis to the QCA.

In addition, an independent assessment of the level of capacity required in new developments has been completed and will be included in ENERGETEX design parameters for subdivision developments.

5. **SUMMARY**

In summary, ENERGETEX's capital contributions policy includes:

- calculation of any required capital contribution by deducting the present value of expected future revenues from the incremental cost of the connection;
- the use of expected DUoS revenues for SAC customers as the basis for calculating incremental revenue;
- discounting expected future revenues using ENERGETEX's approved WACC expressed in pre-tax, real terms;
- allocating 10% of the forecast revenue stream as a contribution to the costs of the existing shared network; and
- taking account of any specific upstream impacts in the calculation of incremental costs, where appropriate.

Appendix 3: Extract of Part E, Chapter 6 of the Rules (National Electricity Rules)⁵

Part E – Distribution Network Pricing

This part of the *Rules* applies to the pricing of *prescribed distribution services* for *distribution networks*, and must be interpreted in accordance with the pricing principles set out in clause 6.1.1 and schedule 6.7.

6.11 Introduction

- (a) Prices for *prescribed distribution services* are based on the averaging of *distribution service costs*.
- (b) Prices for *Distribution Customers* may vary depending on the location, *voltage level* and *load characteristics* of individual *Distribution Customers*.
- (c) *Distribution service* pricing does not permit the concept of point-to-point wheeling arrangements.
- (d) *Distribution service* pricing must be applied to *distribution systems*.
- (e) The *Jurisdictional Regulator* may, in consultation with *Registered Participants*, develop alternative pricing methodologies to the approach set out in Part E. Any new pricing methodology so developed must conform to any jurisdictional rules, principles, or guidelines for the regulation of *distribution* pricing formulated under clause 6.10.1(f).

6.12 Step 1 - Determination of Aggregate Annual Revenue Requirement

To enable regulation of *distribution service* pricing under this Part E, each *Distribution Network Service Provider* must seek from the relevant *Jurisdictional Regulator* a determination of the *Distribution Network Service Provider's aggregate annual revenue requirement* in accordance with Part D.

6.13 Step 2 - Allocation of Distribution Costs

The components of the *aggregate annual revenue requirement* are to be allocated first amongst different assets within classes of *distribution service*, and then to different *cost pools* in accordance with clause 6.14.

6.13.1 Classes of Distribution Service

- (a) Classes of *distribution service* may include:
 - (1) *entry service* which includes the asset-related costs and services provided to serve an *Embedded Generator* or group of *Embedded Generators* at a single *network coupling point* from that *network coupling point* to their *connection point*;

⁵ The Rules have recently been amended and reissued (current version is v18), however in accordance with the Part M of the current Chapter 6 (v.18) ENERGEX is still regulated under the former Chapter 6 during the transitional regulatory period.

- (2) *exit service* which includes the asset-related costs and services provided to serve a *Distribution Customer* or group of *Distribution Customers* at a single *network coupling point* from that *network coupling point* to their *connection point*;
 - (3) *distribution use of system service* which includes the *distribution network* shared by *Embedded Generators* and *Generators connected to a transmission network* where benefits of *new distribution network investment* have been allocated to that *Generator* in accordance with schedule 6.8 and *Distribution Customers*, but excluding *entry service*, *exit service* and *common service*; and
 - (4) *common service* which includes the asset-related costs and services that ensure the integrity of the *distribution system* and benefit all *Distribution Customers* and cannot reasonably be allocated on the basis of *voltage levels* or location.
- (b) *Distribution Network Service Providers* must classify each element and cost of their *distribution services*, including payments made to other *Network Service Providers*, into one of the classes of *distribution services* listed in clause 6.13.1(a).
 - (c) The sum of the *aggregate annual revenue requirement* for each class of *distribution service* must equal the *Distribution Network Service Provider's aggregate annual revenue requirement*.

6.13.2 Allocation of Aggregate Annual Revenue Requirements to Asset Categories within Classes of Network Service

- (a) The assets required by the *Distribution Network Service Provider* to deliver each class of *distribution service* except *common service* may be split into asset categories for the purpose of allocating the *aggregate annual revenue requirement* prior to setting prices.
- (b) The asset categories referred to in clause 6.13.2(a) must be defined by the *Distribution Network Service Provider* and agreed with the *Jurisdictional Regulator* and may include:
 - (1) *use of system voltage levels*; and
 - (2) *connection asset voltage levels*.
- (c) The *Distribution Network Service Provider* may elect to use locational prices and if used, the *Distribution Network Service Provider* must obtain the approval of the *Jurisdictional Regulator* and specify the locations and *voltage levels* for which these locational prices are to apply.
- (d) The *Distribution Network Service Provider* may elect to divide its *network* into geographical areas for one or more *voltage levels* which will represent different zones for pricing purposes and if this occurs, the *Distribution Network Service Provider* must obtain the approval of the *Jurisdictional Regulator* to the geographic boundaries incorporated in the *pricing zones* and of the *voltage levels* of *distribution service* incorporated within these *pricing zones*.

6.13.3 Method of allocation to asset categories

- (a) The *aggregate annual revenue requirement* for an asset category in relation to each class of *distribution service* is to be calculated by the *Distribution Network Service Provider* by allocating the *aggregate annual revenue requirement* for that class of *distribution service* to the asset categories using an allocation basis agreed with the *Jurisdictional Regulator*.
- (b) The method by which the *aggregate annual revenue requirement* is allocated under clause 6.13.3(a) may include:
 - (1) for asset-related costs including return on assets and current cost depreciation charges, the basis may be the replacement cost of the relevant asset categories determined in accordance with any rules specified by the *Jurisdictional Regulator* including rules for treating asset category replacement costs which were provided as partially or fully contributed;
 - (2) chart of accounts information for operating and maintenance costs; or
 - (3) for the *transmission* or *distribution service* costs paid to other *Network Service Providers*, on such basis as may be agreed with the *Jurisdictional Regulator*.
- (c) Payments to and from *Embedded Generators* are to be determined up to an amount of the long run marginal cost of *augmenting the distribution network*, including any other *networks* necessary to cater for additional *generation* at the *network coupling point*, calculated on a case by case basis in accordance with schedule 6.3.
- (d) Any payments made under clause 6.13.3(c):
 - (1) to *Embedded Generators* must be added to: and
 - (2) from *Embedded Generators* must be deducted from,the *aggregate annual revenue requirement* for the relevant asset category consistent with the calculation used to determine that payment.

6.13.4 Allocation of asset category costs to cost pools

- (a) Each *Distribution Network Service Provider* must establish *cost pools* to which *aggregate annual revenue requirements* for all asset categories referred to in clause 6.13.2 must be allocated according to the use of the assets by groups of *Distribution Network Users* having similar *load* characteristics and *voltage* levels, other than in relation to *cost pools* for services provided by *new distribution network investment* assets, for which *cost pools* the *aggregate annual revenue requirements* must be allocated in a manner that is consistent with schedule 6.8.
- (b) Prices for the same *voltage* level and/or *load class* may differ between *pricing zones*.
- (c) *Cost pools* may include *load classes* within each *voltage* level which have similar *load* and/or *metering* characteristics as defined by each *Distribution Network Service Provider*.

- (d) Additional *cost pools* may be included by the *Distribution Network Service Provider* as required by the use of locational and zonal pricing and for any other relevant purpose.
- (e) *Distribution service* prices are to be derived from the costs allocated to each *cost pool*.

6.13.5 Method of allocation to cost pools

- (a) The method of allocating the *aggregate annual revenue requirement* for the asset categories to *cost pools* must be agreed with the *Jurisdictional Regulator*.
- (b) Methods of allocation referred to in clause 6.13.5(a) may include one or more of the following measures:
 - (1) anytime demand;
 - (2) period demand (such as peak, shoulder and off-peak);
 - (3) coincident demand;
 - (4) period *energy* (such as peak, shoulder and off-peak);
 - (5) anytime *energy*; and
 - (6) *load cycle* basis (method of intercepts).

6.13.6 Cost allocation to Distribution Customers and Embedded Generators

Distribution service costs must be allocated to *Embedded Generators* and *Distribution Customers* as follows:

- (a) The *cost pools* for *entry services* must all be allocated to *Embedded Generators* at the *network coupling point*.
- (b) The *cost pools* for *exit services* must all be allocated to *Distribution Customers* at the *network coupling point*.
- (c) In respect of the *cost pools* for *distribution use of system services* (as defined in clause 6.13.1(a)(3)):
 - (1) the portion of the *distribution use of system* costs allocated to *Embedded Generators* must not exceed the long run marginal cost of *augmenting the distribution network* and any other *networks* necessary to cater for additional *generation* at the *network coupling point*, calculated on a case by case basis in accordance with schedule 6.3; and
 - (2) the portion of the *distribution use of system* costs allocated to *Distribution Customers* must be done on a cost reflective or other basis agreed with the *Jurisdictional Regulator*.
- (d) The *cost pools* for common services must be allocated to *Distribution Customers* (other than *Market Network Service Providers* as they are not required to pay for *common services*) on a cost reflective or other basis agreed with the *Jurisdictional Regulator*.

- (e) Where *entry services* are shared by *Embedded Generators* and *exit services* are shared by *Distribution Customers*, the allocated cost must be shared between the *Distribution Network Users* either:
 - (1) as agreed with the *Distribution Network Users*; or
 - (2) on a cost reflective or other basis agreed with the *Jurisdictional Regulator*, or
 - (3) on the basis of the *maximum demand* of individual *Distribution Network Users* at a *network coupling point*, measured in respect of the 10 hours for which the *Distribution Network User* has used the *network* most intensively during the preceding year.
- (f) The *cost pools* for services provided by *new large distribution network assets* and *new small distribution network assets* must be allocated to *Embedded Generators* and *Generators connected to a transmission network*, where benefits of *new distribution network investment* have been allocated to that *Generator* in accordance with schedule 6.8, and *Distribution Customers*, in a manner which is consistent with schedule 6.8.

6.13.7 Treatment of network service costs paid to other Network Service Providers

- (a) A *Distribution Network Service Provider* must pay *transmission service costs* to a *Transmission Network Service Provider* in respect of the *Distribution Network Service Provider's* use of a *transmission network* at each *connection point* on the *transmission network*.
- (b) The *transmission service costs* referred to in clause 6.13.7(a) must be allocated to asset categories using an appropriate allocation method agreed with the *Jurisdictional Regulator* and consistent with the objective of the *distribution service pricing regulatory regime* set out in clause 6.10.2(b)(4).
- (c) Where a *Distribution Network Service Provider* uses other *distribution networks*, *distribution service costs* must be paid by that *Distribution Network Service Provider* to the owner of those other *distribution networks* for the use of those other *distribution networks* at each *network coupling point*.
- (d) The *distribution service costs* referred to in clause 6.13.7(c) must be allocated to asset categories using an appropriate allocation method agreed with the *Jurisdictional Regulator*.

6.14 Step 3 - Usage Based Prices for Distribution Network Service

The outcome of the cost allocation process specified in clause 6.13 is a number of *cost pools* containing allocated annual costs referable to categories which may include one or more of the following classes depending on the type of *Embedded Generator* or *Distribution Customer* receiving *distribution service* at each *connection point*. Typical *cost pools* include:

- (a) *Embedded Generator entry costs*;
- (b) *Distribution Customer exit costs*;
- (c) *Embedded Generator distribution use of system costs*;

- (d) *Distribution Customer distribution use of system costs;*
- (e) *Distribution Customer common service costs;*
- (f) *new large distribution network asset costs; and*
- (g) *new small distribution network asset costs.*

These classes of cost may be converted into prices in accordance with clauses 6.14.1 to 6.14.3.

6.14.1 Embedded Generator Prices

- (a) The *Embedded Generator* charge for *prescribed distribution services* may incorporate *entry costs*.
- (b) The charge payable by an *Embedded Generator* for *entry services* is a fixed annual amount equal to the *entry cost* allocated to each *Embedded Generator* under clause 6.13.6(a) unless the charge for those *entry services* has been agreed in a current *connection agreement* with the *Embedded Generator*.
- (c) The charge payable by an *Embedded Generator* for *negotiated use of system services* must be determined in accordance with clause 5.5(f)(2) and the parties may seek recourse to the *Jurisdictional Regulator* in the event of a dispute.
- (d) There may be other charges applicable to *distribution services* for *Embedded Generators*, including local *connection* requirements and any risk premium associated with the provision of *generator access* between the *Embedded Generator* and the *Distribution Network Service Provider* and such charges must be agreed between the *Embedded Generator* and the relevant *Distribution Network Service Provider*. Any revenue received from charges for *generator access* does not form part of the relevant *Distribution Network Service Provider's* aggregate annual revenue requirement.
- (e) There may be situations where the *Distribution Network Service Provider* is prepared to pay for equivalent *distribution services* by *Embedded Generators*. These arrangements are set out in clause 6.10.5(d)(7)(iii) and payments for such equivalent *distribution services* are to be agreed between the relevant *Distribution Network Service Provider* and *Jurisdictional Regulator*.
- (f) Where an *Embedded Generator* benefits from *new large distribution network assets* or *new small distribution network assets* as determined in accordance with clause 5.6.2, the charge payable by the *Embedded Generator* for the services provided by those new assets will be as determined in accordance with schedule 6.8.

6.14.2 Distribution Customer Price

- (a) The charges payable by a *Distribution Customer* for *prescribed distribution services* may incorporate *exit costs*, *distribution use of system costs* and *common service costs*.
- (b) The charge payable by *Distribution Customers* is to be determined as an amount consistent with the following (subject to any relevant *price cap* level):

- (1) a fixed amount equal to the *exit cost* allocated in accordance with clause 6.13.6(b); plus
 - (2) a variable amount so that costs for *distribution use of system* allocated to *Distribution Customers* under clause 6.13.6(c) are fully recovered; plus
 - (3) a variable amount so that costs for *common service* allocated to *Distribution Customers* under clause 6.13.6(d) are fully recovered.
- (c) The *Distribution Customer* price structure is to be determined by the *Distribution Network Service Provider*.
- (d) The prices determined under this sub-clause may comprise one or more elements related to:
- (1) *demand based prices* (eg. \$ per maximum kW per period or \$ per maximum kV.A per period, which may include a time of use component);
 - (2) *energy based prices* (eg. ¢ per kWh or ¢ per kV.A which may include a time of use component); and
 - (3) *Distribution Customer charges* (eg. \$ per *Distribution Customer* per period).
- (e) Where quantities are used in determining charges, these quantities may be minimum quantities specified in the prices, actual quantities used by the *Distribution Customer* or quantities agreed by the *Distribution Customer* and *Distribution Network Service Provider*. The pricing outcome will be subject to regulation as outlined in clause 6.14.4.
- (f) Where the charge payable for *exit services* has been agreed between a *Distribution Customer* and the relevant *Distribution Network Service Provider* in a current *connection agreement*, the charge payable by that *Distribution Customer* determined under clause 6.14.2(b) must not include any amount attributable to *exit costs*.

6.14.3 Prices for Network Users that are both Distribution Customers and Embedded Generators

- (a) *Distribution Network Users* may have *connection points* that combine *Embedded Generators* and *Distribution Customers*. Depending on the relative status of the relevant *generation* and the *load*, the *connection point* could represent a net *Distribution Customer* or a net *Embedded Generator*. Where the net loading position at a *connection point* fluctuates between net import and net export during a *billing period* the following conditions are to apply:
- (1) periods of net export of *energy* will be subject to *Embedded Generator* pricing arrangements; and
 - (2) periods of net import of *energy* will be subject to *Distribution Customer* pricing arrangements.
- (b) For *Distribution Customers* where there is no export of *generation* into the *distribution network*, prices are to be applied and payable as determined under clause 6.14.2.

- (c) For *Embedded Generators* where there is no consumption of electricity from the *distribution network* by a *Distribution Customer*, prices are to be applied and payable as determined under clause 6.14.1 provided that the *Embedded Generator* must not be charged twice for the use of the same assets.

6.14.4 Regulation of Distribution Prices

- (a) The *Jurisdictional Regulator* may place limits on the annual variation in published *distribution service* prices. Any such limits must be specified by the *Jurisdictional Regulator* at the commencement of the *regulatory control period* and are to apply for the duration of the *regulatory control period*.
- (b) Pricing outcomes for *Distribution Customers* under clause 6.14.4 must not be inconsistent with any applicable jurisdictional requirements and any applicable *price cap* level.

6.14.5 Publication of Distribution Network Prices

- (a) Each *Distribution Network Service Provider* in conjunction with the *Jurisdictional Regulator* must publish by 31 May each year:
 - (1) a schedule of prices for all classes of *distribution services* at each *voltage* level, *load class* and *pricing zone* where the schedule prices are to be the maximum price charged;
 - (2) a statement providing details of principles and methods for determining *connection* charges; and
 - (3) the service standards to which it will adhere for the services to which those *distribution service* prices relate, which service standards must include, and not be inconsistent with, any service standards imposed on the *Distribution Network Service Provider* by any regulatory regime administered by the *Jurisdictional Regulator*,to apply to *Distribution Customers* and *Embedded Generators* in the following year, commencing 1 July.
- (b) Price variations other than on an annual basis can only be made with the approval of the *Jurisdictional Regulator* who will also determine the amount of notice which should be given before implementation of the new price.

6.14.6 Agreement as to Distribution Prices

- (a) Subject to clause 6.14.6(b) and (c), the prices determined in accordance with clauses 6.14.1 to 6.14.3, or the prices determined by the application of a price cap, are the maximum prices which a *Distribution Network Service Provider* is entitled to charge for providing the relevant *prescribed distribution services* to:
 - (1) the standards described in schedule 5.1; and
 - (2) the standards published in accordance with clause 6.14.5(a)(3),notwithstanding any agreement with another person to the contrary.

- (b) A *Distribution Network Service Provider* may, but is not required to, agree with a *Distribution Network User* to charge that *Distribution Network User* lower prices than those described in clause 6.14.6(a) and, if the relevant parties have so agreed, the prices payable by that *Distribution Network User* for the provision of the relevant *prescribed distribution services* are those so agreed rather than those described in clause 6.14.6(a).
- (c) If a *Distribution Network Service Provider* agrees to provide a *Distribution Network User* with *prescribed distribution services* to higher or lower standards than those described in schedule 5.1 or the standards published in accordance with clause 6.14.5(a)(3), then the prices payable by the *Distribution Network User* as a result of the difference between the level prescribed by schedule 5.1 or the standards published in accordance with clause 6.14.5(a)(3) and the agreed higher or lower standard are to be those agreed between the *Distribution Network Service Provider* and the relevant *Distribution Network User* in accordance with clause 6.14.7, provided that the reductions in prices payable by the *Distribution Network User* for the provision of *prescribed distribution services* to a lower standard are limited to the amount of the *Distribution Network Service Provider's* avoided costs (if any) as a result of the provision of services to that lower standard.

6.14.7 Pricing of Negotiable Services

- (a) Each *Distribution Network Service Provider* (other than a *Market Network Service Provider*) must establish a framework in accordance with the requirements of clause 6.14.7(b) (the "*negotiating framework*") setting out the minimum requirements to be followed during negotiations with *Distribution Network Users* for *negotiable services*.
- (b) For the purposes of clause 6.14.7(a), the *negotiating framework* must specify:
 - (1) a requirement for the *Distribution Network Service Provider* and the *Distribution Network User* to negotiate in good faith for the provision of *negotiable services*;
 - (2) notwithstanding clause 6.18.2, a requirement for the *Distribution Network Service Provider* to provide all such commercial information as the *Distribution Network User* may reasonably require to enable the *Distribution Network User* to engage in effective negotiation with the *Distribution Network Service Provider* for the provision of *negotiable services*, including the cost information described in clause 6.14.7(b)(3);
 - (3) a requirement for the *Distribution Network Service Provider* to:
 - (i) identify, and inform the *Distribution Network User* of, the reasonable costs and/or the increase or decrease in costs (as appropriate), of providing those *negotiable services*; and
 - (ii) demonstrate to the *Distribution Network User* that its charges for providing those *negotiable services* reflect those costs and/or the cost increment or decrement (as appropriate);
 - (4) a requirement for the *Distribution Network User* to provide all such commercial information as the *Distribution Network Service Provider* may reasonably require to enable the *Distribution Network Service Provider* to

engage in effective negotiation with the *Distribution Network User* for the provision of *negotiable services*;

- (5) a reasonable period of time for commencing, progressing and finalising negotiations with the *Distribution Network User* for the provision of *negotiable services*, and a requirement that each party to the negotiation must use its reasonable endeavours to adhere to those time periods during the negotiation;
- (6) a process for dispute resolution which provides for all disputes arising out of or concerning negotiations for negotiable services to be dealt with in accordance with clause 8.2 or, where the *Distribution Network User* is not a *Registered Participant*, in accordance with a specified alternative dispute resolution process;
- (7) a requirement to publish the outcome of the negotiation to provide *negotiable services*; and
- (8) the arrangements for payment by the *Distribution Network User* of the *Distribution Network Service Provider's* reasonable direct expenses incurred in processing the application to provide the *negotiable services*; and
- (9) a requirement that the *Distribution Network Service Provider* determine the potential impact on other *Distribution Network Users* of the negotiated provision of a prescribed distribution service to a higher or lower standard than any standard:
 - (i) described in schedule 5.1; or
 - (ii) published by the *Distribution Network Service Provider* in accordance with clause 6.14.5(a)(3),

and a requirement that the *Distribution Network Service Provider* must notify and consult with any affected *Distribution Network Users* and ensure that the provision of these *negotiable services* does not result in non-compliance with any service standards or other obligations in relation to other *Distribution Network Users* under the *Rules*.

- (c) Each *Distribution Network Service Provider* must:
 - (1) have its *negotiating framework* developed in accordance with clause 6.14.7(b) approved by the *Jurisdictional Regulator*, and
 - (2) comply with the requirements of the *negotiating framework* in accordance with its terms and subject to any amendments or conditions imposed by the *Jurisdictional Regulator*.
- (d) For the avoidance of doubt, commercial information which is required to be provided to a *Distribution Network User* in accordance with clause 6.14.7(b)(2):
 - (1) does not include confidential information provided to the *Distribution Network Service Provider* by another person; and
 - (2) may be provided subject to a condition that the *Distribution Network User* must not provide any part of that commercial information to any other

person without the consent of the Distribution Network Service Provider which provided the information to the Distribution Network User.

- (e) For the avoidance of doubt, commercial information which is required to be provided to a *Distribution Network Service Provider* in accordance with clause 6.14.7(b)(4):
 - (1) does not include confidential information provided to the *Distribution Network User* by another person; and
 - (2) may be provided subject to a condition that the *Distribution Network Service Provider* must not provide any part of that commercial information to any other person without the consent of the *Distribution Network User* which provided the information to the *Distribution Network Service Provider*.

6.15 Distribution Network Service Provider Prudential Requirements

This clause sets out the arrangements by which *Distribution Network Service Providers* may minimise financial risks associated with investment in *network assets*, and provides for the adoption of cost-reflective payment options in conjunction with the use of average *distribution* prices. The clause also prevents *Distribution Network Service Providers* from receiving income twice for the same assets through prudential requirements and *distribution service* prices.

6.15.1 Prudential Requirements for Distribution Network Service

- (a) A *Distribution Network Service Provider* may require an *Embedded Generator* or *Distribution Customer* that requires a new *connection* or a modification in service for an existing *connection* to establish prudential requirements for *connection service* and/or *distribution use of system service*.
- (b) Prudential requirements for *connection service* and/or *distribution use of system service* are a matter for negotiation between the *Distribution Network Service Provider* and the *Embedded Generator* or *Distribution Customer* and the terms agreed must be set out in the *connection agreement* between the *Distribution Network Service Provider* and the *Embedded Generator* or *Distribution Customer*.
- (c) The *connection agreement* may include one or more of the following provisions:
 - (1) the conditions under which and the time frame within which other *Distribution Network Users* who use that part of the *distribution network* contribute to refunding all or part of the payments;
 - (2) the conditions under which financial arrangements may be terminated; and
 - (3) the conditions applying in the event of default by the *Distribution Customer* or *Embedded Generator*.
- (d) The prudential requirements may incorporate, but are not limited to, one or more of the following arrangements:
 - (1) financial capital contributions;
 - (2) non-cash asset contributions;

- (3) *distribution service* charge prepayments;
- (4) guaranteed minimum *distribution service* charges for an agreed period;
- (5) guaranteed minimum *distribution service* quantities for an agreed period;
and
- (6) provision of financial guarantees for *distribution service* charges.

6.15.2 Capital Contributions, Prepayments and Financial Guarantees

In relation to capital contributions, prepayments and financial guarantees:

- (a) the *Distribution Network Service Provider* is not entitled to receive any asset related cost component of the *aggregate annual revenue requirement* for assets provided by *Distribution Network Users*;
- (b) the *Distribution Network Service Provider* may receive a capital contribution, prepayment and/or financial guarantee up to the future *aggregate annual revenue requirement* for any new assets installed as part of a new *connection* or modification to an existing *connection*, including any *augmentation* to the *distribution network*;
- (c) where assets have been the subject of a contribution or prepayment, the *Distribution Network Service Provider* must amend the *aggregate annual revenue requirement*; and
- (d) the asset categories referred to in clause 6.13.3 must not incorporate the asset related cost components of the *aggregate annual revenue requirement* for any asset category covered by clause 6.15.2 and the *Distribution Network Users* who use any such asset together as a group are to pay less for the ongoing use of that asset category than they otherwise would have paid.

6.15.3 Treatment of Past Prepayments and Capital Contributions

- (a) Payments made by *Distribution Customers* and *Embedded Generators* for *distribution service* prior to 13 December 1998 must be made in accordance with any contractual arrangements with the relevant *Distribution Network Service Providers* applicable at that time.
- (b) Where contractual arrangements referred to in clause 6.15.3(a) are not in place, past *distribution service* prepayments or capital contributions may be incorporated in the capital structure of the *Distribution Network Service Provider's* business.
- (c) The *Jurisdictional Regulator* may intervene in and resolve any dispute under this clause 6.15.3 which cannot be resolved between the relevant *Distribution Network Service Provider* and *Distribution Customer* or *Embedded Generator*.

6.16 Billing and Settlements Process

This clause describes the manner in which *Distribution Customers* and *Embedded Generators* are billed by *Distribution Network Service Providers* for *distribution service* and how payments for *distribution service* are settled.

6.16.1 Billing for Distribution Services

- (a) A *Distribution Network Service Provider* must bill *Distribution Network Users* for *distribution service* as follows:
- (1) *Embedded Generators*:
 - (i) by applying the *entry charge* as a fixed annual charge to each *Embedded Generator*; and
 - (ii) by applying the *Generator distribution use of system* price to the *Embedded Generator's* nominated capacity.
 - (2) *Distribution Customers*:

The charges to *Distribution Customers* must be determined according to use of the *distribution network* as determined in accordance with a *metrology procedure* or, in the absence of a *metrology procedure* allowing such a determination to be made, by a *meter* or by agreement between the *Distribution Customer* and the *Distribution Network Service Provider* by applying one or more of the following measures:

 - (i) demand-based prices to the *Distribution Customer's* metered or agreed half-hourly demand;
 - (ii) energy-based prices to the *Distribution Customer's* metered or agreed energy;
 - (iii) the *Distribution Customer* charge determined under this clause 6.16 as a fixed periodic charge to each *Distribution Customer*, and
 - (iv) a fixed periodic charge, a prepayment or other charge determined by agreement with the *Distribution Customer*.
- (b) Subject to clause 6.16.1(c), where a *Distribution Customer* (other than a *Market Customer*) incurs *distribution service* charges, the *Distribution Network Service Provider* must bill the *Market Customer* from whom the *Distribution Customer* purchases electricity directly or indirectly for such *distribution services* in accordance with clause 6.16.1(a)(2).
- (c) If a *Distribution Customer* and the *Market Customer* from whom it purchases electricity agree, the *Distribution Network Service Provider* may bill the *Distribution Customer* directly for *distribution services* used by that *Distribution Customer* in accordance with clause 6.16.1(a)(2).
- (d) *Distribution Network Service Providers* must:
- (1) calculate *transmission service* charges and *distribution service* charges for all *connection points* in their *distribution network*; and
 - (2) pay to *Transmission Network Service Providers* the *transmission service* charges incurred in respect of use of a *transmission network* at each *connection point* on the relevant *transmission network*.
- (e) Charges for distribution services based on metered kW, kWh, kV.A or kV.Ah for:

- (1) *Embedded Generators* that are *Market Generators*;
- (2) *Market Customers*; and
- (3) *Second-Tier Customers*,

must be calculated by the *Distribution Network Service Provider* from:

- (1) *settlements ready data* obtained from NEMMCO's *metering database*, for those *Embedded Generators*, *Market Customers* and *Second-Tier Customers* with *connection points* that have a type 1, 2, 3 or 4 *metering installation*; and
 - (2) *energy data*, in accordance with a *metrology procedure* that allows the *Distribution Network Service Provider* to use *energy data* for this purpose, or otherwise *settlements ready data* obtained from NEMMCO's *metering database*, for those *Embedded Generators*, *Market Customers* and *Second-Tier Customers* with *connection points* that have a type 5, 6 or 7 *metering installation*.
- (f) Charges for *distribution services* based on *metered kW*, *kWh*, *kV.A* or *kV.Ah* for:
- (1) *Embedded Generators* that are not *Market Generators*;
 - (2) *Non-Registered Customers*; and
 - (3) *franchise customers*,
- must be calculated by the *Distribution Network Service Provider* using data that is consistent with the *metering data* used by the relevant *Local Retailer* in determining *energy settlements*.
- (g) The *Distribution Network Service Provider* may bill the relevant *Local Retailer* for *distribution services* used by *Non-Registered Customers* and *franchise customers*.
- (h) Where the billing for a *Distribution Customer* for a particular *financial year* is based on quantities which are undefined until after the commencement of the *financial year*, charges must be estimated from the previous year's billing quantities with a reconciliation to be made when the actual billing quantities are known.
- (i) Where the previous year's billing quantities are unavailable or no longer suitable, nominated quantities may be used as agreed between the parties.

6.16.2 Minimum information to be provided in distribution network service bills

The following is the minimum information that must be provided with a bill for a *network coupling point* issued by a *Distribution Network Service Provider* directly to a *Registered Participant*.

- (a) the *network coupling point* identifier;
- (b) the dates on which the *billing period* starts and ends;

- (c) the identifier of the *distribution service* price from which the *network coupling point* charges are calculated; and
- (d) measured quantities, billed quantities, prices and amounts charged for each component of the total *distribution service* account.

6.16.3 Settlement Between Distribution Network Service Providers

The billing and *settlement* process specified in this clause 6.16 must be applied to all *Distribution Customers* including other *Distribution Network Service Providers*.

6.16.4 Obligation to Pay

A *Distribution Network User* must pay *distribution service* charges properly charged to it and billed in accordance with this clause 6.16 by the due date specified in the bill.

6.17 Distribution Network Service Pricing Records

Each *Distribution Network Service Provider* must maintain appropriate *distribution service* pricing records that satisfy any requirements of the *Jurisdictional Regulator*.

6.18 Data Required for Distribution Network Service Pricing

6.18.1 Forecast Use of Networks by Distribution Customers and Embedded Generators

Any information required by *Distribution Network Service Providers* must be provided by *Registered Participants* as part of the *connection* and access requirements set out in Chapter 5.

6.18.2 Confidentiality of Distribution Network Pricing Information

All information used by *Distribution Network Service Providers* for the purposes of *distribution service* pricing is *confidential information* and must be treated in accordance with clause 8.6.

Appendix 4: Variation of Part E, Chapter 6 of the Rules

6.14.5 PUBLICATION OF DISTRIBUTION NETWORK PRICES

The Rules requires that DNSPs publish network prices for all classes of distribution service at each voltage level. As network prices for ICCs and CACs are individually determined and are considered commercially sensitive information, these prices will be forwarded directly to the customer and their Retailer Of Choice and will not be placed in the public domain. Network prices for all SACs consuming less than 4.0GWH per annum are included in a Price Schedule and will be published.

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

- (a) Distribution Network Service Providers in conjunction with the Jurisdictional Regulator must publish by 31 May each year:
 - (1) a schedule of network prices including terms and conditions for all standard asset customers (SAC) and the shared network (averaged) component of network prices for CACs where the schedule prices 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.
- (b) Network prices for ICCs and CACs will not be published but will supplied directly to the customer and their Retailer Of Choice.
- (c) (d) 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 as agreed with the relevant regulator.

6.15.2 Capital Contribution Pre-payments and Financial Guarantees

The Rules requires that network businesses do not impose capital related charges for assets contributed by customers. 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 network businesses 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:

- network users should not be charged for assets to which they have contributed;
- DNSPs have a practical difficulty in separately identifying and managing on an on-going basis those assets, or parts of assets, have been contributed to by individual network users; and
- 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:

- (a) The QCA shall approve the level of capital contributions when determining the DNSP's Revenue Cap for connection and access services.

- (b) 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).
- (c) Capital contributions made after the commencement of the Rules in Queensland (18 January 1998) by
 - I. ICCs, or
 - II. CACs for connection assets only

for which site specific network charges would apply will be eligible for recognition of that capital contribution upon the customer becoming contestable. The period of recognition shall not exceed the life of the assets towards which the contribution was made.

- (d) Capital contributions made by Standard Asset Customers are pre-payments of revenue shortfall and therefore will not be specifically recognised as the customer has paid such capital contribution to access a published network price schedule

6.16.1 Billing for Distribution Network Services

- (a) The Distribution Network Service Provider must bill for connection and access services based on the approved network charges.
- (b) Subject to Clause 6.16.1(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 6.16.1(a)
- (c) 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 6.16.1(a)
- (d) Distribution Network Service Providers must:
 - (1) Calculate transmission service charges and connection and access charges for all connection points in their distribution network; and
 - (2) Pay to Transmission Network Service Providers the transmission service charges incurred in respect of use of a transmission network at each connection point on the relevant transmission network.
- (e) Charges for connection and access services based on metered or agreed or nominated or Authorised kW, kW.h, kV.A or kV.Ah 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.
- (f)

6.16.2 Minimum Information to be Provided in Network Service Bills for Contestable Network Users

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

- (a) the National Metering Identifier (NMI);
- (b) the dates on which the billing period starts and ends;

- (c) the measured quantities, billed quantities, prices and amounts charged for each component of the Distribution Customer's.

6.16.4 Obligation to Pay

A Market Customer, Customer, or Embedded Generator must pay distribution service charges properly charged to it and billed in accordance with clause 6.16 by the due date specified in the bill.

Appendix 5: Extract of Clause 5.5 of the Rules

5.5 Access arrangements relating to Distribution Networks

- (a) In this rule 5.5:
- (1) the *Distribution Network Service Provider* is the *Distribution Network Service Provider* required under clause 5.3.3 to process and respond to a *connection* enquiry or required under clause 5.3.5 to prepare an offer to *connect* for the establishment or modification of a *connection* to the *distribution network* owned, controlled or operated by that *Distribution Network Service Provider* or for the provision of *network service*; and
 - (2) the references to a *Connection Applicant* are to an *Embedded Generator* or *Market Network Service Provider* who makes a *connection* enquiry under clause 5.3.2 or an application to *connect* under clause 5.3.4 in relation to any *generating units* or group of *generating units*, or any *network elements* used in the provision of *network service*, as the case may be.
- (b) If requested by a *Connection Applicant*, whether as part of a *connection* enquiry, application to *connect* or the subsequent negotiation of a *connection agreement*, the *Distribution Network Service Provider* must negotiate in good faith with the *Connection Applicant* to reach agreement in respect of the *distribution network user access arrangements* sought by the *Connection Applicant*.
- (c) As a basis for negotiations under paragraph (b):
- (1) the *Connection Applicant* must provide to the *Distribution Network Service Provider* such information as is reasonably requested relating to the expected operation of:
 - (i) its *generating units* (in the case of an *Embedded Generator*); or
 - (ii) its *network elements* used in the provision of *network service* (in the case of a *Market Network Service Provider*); and
 - (2) the *Distribution Network Service Provider* must provide to the *Connection Applicant* such information as is reasonably requested to allow the *Connection Applicant* to fully assess the commercial significance of the *distribution network user access arrangements* sought by the *Connection Applicant* and offered by the *Distribution Network Service Provider*.
- (d) A *Connection Applicant* may seek *distribution network user access arrangements* at any level of *power transfer capability* between zero and:
- (1) in the case of an *Embedded Generator*, the *maximum power input* of the relevant *generating units* or group of *generating units*; and
 - (2) in the case of a *Market Network Service Provider*, the *power transfer capability* of the relevant *network elements*.
- (e) The *Distribution Network Service Provider* must use reasonable endeavours to provide the *distribution network user access arrangements* being sought by the *Connection Applicant* subject to those arrangements being consistent with *good electricity industry practice* considering:
- (1) the *connection assets* to be provided by the *Distribution Network Service Provider* or otherwise at the *connection point*; and

- (2) the potential *augmentations* or *extensions* required to be undertaken on all affected *transmission networks* or *distribution networks* to provide that level of *power transfer capability* over the period of the *connection agreement* taking into account the amount of *power transfer capability* provided to other *Registered Participants* under *transmission network user access* or *distribution network user access* arrangements in respect of all affected *transmission networks* and *distribution networks*.
- (f) The *Distribution Network Service Provider* and the *Connection Applicant* must negotiate in good faith to reach agreement as appropriate on:
- (1) the *connection service charge* to be paid by the *Connection Applicant* in relation to *connection assets* to be provided by the *Distribution Network Service Provider*;
 - (2) in the case of a *Market Network Service Provider*, the service level standards to which the *Market Network Service Provider* requires the *Distribution Network Service Provider* to adhere in providing its services;
 - (3) the *use of system services charge* to be paid:
 - (i) by the *Connection Applicant* in relation to any *augmentations* or *extensions* required to be undertaken on all affected *transmission networks* and *distribution networks*; and
 - (ii) where the *Connection Applicant* is a *Market Network Service Provider*, to the *Market Network Service Provider* in respect of any reduction in the long run marginal cost of *augmenting* the *distribution network* as a result of it being *connected* to the *distribution network*,

(‘*negotiated use of system charges*’); and
 - (4) the following amounts:
 - (i) the amount to be paid by the *Connection Applicant* to the *Distribution Network Service Provider* in relation to the costs reasonably incurred by the *Distribution Network Service Provider* in providing *distribution network user access*;
 - (ii) where the *Connection Applicant* is an *Embedded Generator*:
 - (A) the compensation to be provided by the *Distribution Network Service Provider* to the *Embedded Generator* in the event that the *generating units* or group of *generating units* of the *Embedded Generator* are *constrained off* or *constrained on* during a *trading interval*; and
 - (B) the compensation to be provided by the *Embedded Generator* to the *Distribution Network Service Provider* in the event that dispatch of the *Embedded Generator’s generating units* or group of *generating units* causes another *Generator’s generating units* or group of *generating units* to be *constrained off* or *constrained on* during a *trading interval*; and

- (iii) where the *Connection Applicant* is a *Market Network Service Provider*:
 - (A) the compensation to be provided by the *Distribution Network Service Provider* to the *Market Network Service Provider* in the event that the *distribution network user access* is not provided; and
 - (B) the compensation to be provided by the *Market Network Service Provider* to the *Distribution Network Service Provider* in the event that *dispatch* of the relevant *market network service* causes a *Generator's generating units* or group of *generating units* to be *constrained off* or *constrained on* during a *trading interval* or causes the *dispatch* of another *market network service* to be *constrained*.
- (g) The maximum negotiated *use of system* charges applied by a *Distribution Network Service Provider* must be in accordance with the applicable requirements of Chapter 6 and the *Negotiated Distribution Service Criteria* applicable to the *Distribution Network Service Provider*.
- (h) A *Distribution Network Service Provider* must pass through to a *Connection Applicant* the amount calculated in accordance with paragraph (i) for the locational component of *prescribed TUOS services* that would have been payable by the *Distribution Network Service Provider* to a *Transmission Network Service Provider* had the *Connection Applicant* not been *connected* to its *distribution network* ('avoided charges for the locational component of *prescribed TUOS services*').
- (i) To calculate the amount to be passed through to a *Connection Applicant* in accordance with paragraph (h), a *Distribution Network Service Provider* must, if prices for the locational component of *prescribed TUOS services* were in force at the relevant *transmission network connection point* throughout the relevant *financial year*:
 - (1) determine 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*:
 - (i) where the *Connection Applicant* is an *Embedded Generator*, if that *Embedded Generator* had not injected any *energy* at its *connection point* during that *financial year*;
 - (ii) where the *Connection Applicant* is a *Market Network Service Provider*, if the *Market Network Service Provider* had not been *connected* to the *Distribution Network Service Provider's distribution network* during that *financial year*; and
 - (2) determine the amount by which the charges calculated in subparagraph (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 paragraph (h).
- (j) Where prices for the locational component of *prescribed TUOS services* were not in force at the relevant *distribution network connection point* throughout the relevant *financial year*, as referred to in paragraph (i), the *Distribution Network Service Provider* must apply an equivalent procedure

to that referred to in paragraph (i) in relation to that component of its *transmission use of system service* charges which is deemed by the relevant *Transmission Network Service Provider* to represent the marginal cost of *transmission*, less an allowance for locational signals present in the *spot market*, to determine the relevant amount for the purposes of paragraph (h).

Appendix 6: Explanation of kW v kV.A

Alternating current (AC) electrical systems are generally characterised by a number of power components, namely real power and reactive power. These are defined as:

- Real Power – the power required to provide heat, motive power and the like which is measured in kilowatts (kW); and
- Reactive power – the power required to energise electric and magnetic fields that are ancillary to the production of real power. Reactive power is measured in KiloVolt Amps reactive (kvar).

The relationship between kW and kvar gives kV.A. The relationship is illustrated in Figure 3 below.

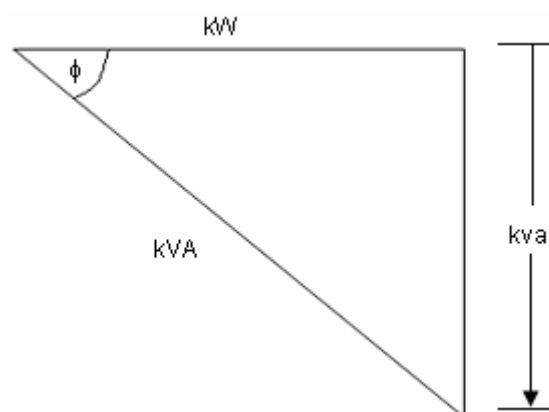


Figure 3: Power Triangle

To illustrate power components, consider the Figure 4. The person is pulling a block from point A to point B. It can be seen that in the work done pulling the rope can be broken up into two components, one horizontal (H) and one vertical (V). To do the minimum amount of work, the person would have to pull the block in only the horizontal direction (H). This is however not possible and there will always be a force in the vertical direction. This vertical force (V) does not contribute to the block moving from A to B, however it is required due to the height of the person. The total force required to move the block is the result of both the horizontal and the vertical force together.

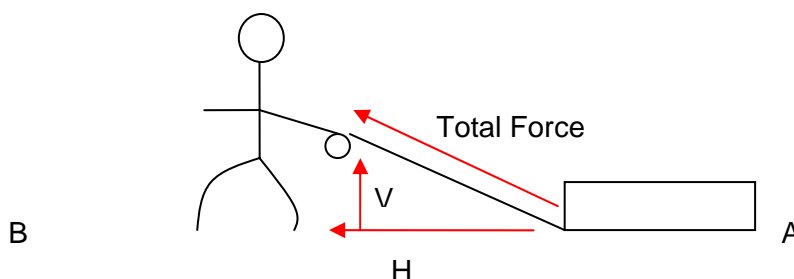


Figure 4: Illustration of real and reactive power

In terms of power, real power may be considered the horizontal force because it does the actual work. However, most electrical apparatus (loads) in a plant require a magnetic field to operate. Reactive power provides this field, although it does not do any useful work.

The total power or apparent power (the total power consumed by loads), kV.A, is the vector sum of the real and reactive power, as indicated in figure 3 and the formula below:

$$\text{kVA} = \sqrt{(\text{kW}^2 + \text{k var}^2)}$$

The power factor of the load is represented by the cosine of the phase angle between kV.A and kW. It acts as a measurement of how efficiently a facility is using electrical energy.

$$\text{Power Factor} = \cos(\varphi_1)$$

Apart from a small variety of electrical equipment such as heating apparatus, the majority of domestic and industrial applications require reactive power to operate. This means that the transmission and distribution systems must be designed to manage the need for real power and its associated reactive component. Using kV.A as a pricing mechanism is therefore a more accurate means to ensure that customers are paying for the capacity of the network they use.