KPMG

City of Greater Bendigo

National Electricity Equity (Business) Project

Final Report

July 2007

This report contains 125 pages

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Contents

1 Executive summary

1.1 Regional network customers bear higher prices

Since the early 1990s and the introduction of National Competition Policy, Australia's electricity supply industry has undergone significant reform. This has resulted in formerly vertically integrated, state-based electricity supply industries being disaggregated to allow competition in the retail and generation sectors and to provide economically efficient pricing and access to monopoly networks such as electricity transmission and distribution.

Since the introduction of the National Electricity Code (now the National Electricity Rules) in 1998, electricity network pricing in the National Electricity Market (the NEM) has been governed by a single set of rules intended to provide prices that replicate the outcomes of efficient competitive markets. Consequently, electricity network pricing has become increasingly reflective of efficient cost. This is intended to both provide efficient prices for customers and meet the costs of and stimulate appropriate network investment by network owners. However, greater investment and costs are generally required to build and maintain extended rural and regional electricity networks, which serve a less dense population of customers than metropolitan networks. Accordingly, relatively high costs are allocated to relatively few regional and rural customers. As a result, they generally bear higher network prices than their metropolitan counterparts.

However, regional business customers may not be in a practical position to manage these cost differentials where:

- they may be unable to pass through increased costs where their markets are also served by competitors located outside of regional Australia; and

- it may be impractical or damaging to the regional social structure for businesses to move to lower cost locations.

Both of these outcomes are likely to have adverse local economic impacts which may be exacerbated in regional economies that may be more sensitive to and less able to deal with, the effects of relatively small reductions in investment, than metropolitan areas.

The following examples illustrate the differentials in electricity network prices for business customers within a range of jurisdictions in the NEM[1]. These examples draw on data for actual regional customers selected at random from the sample of customers that contributed data to this report.

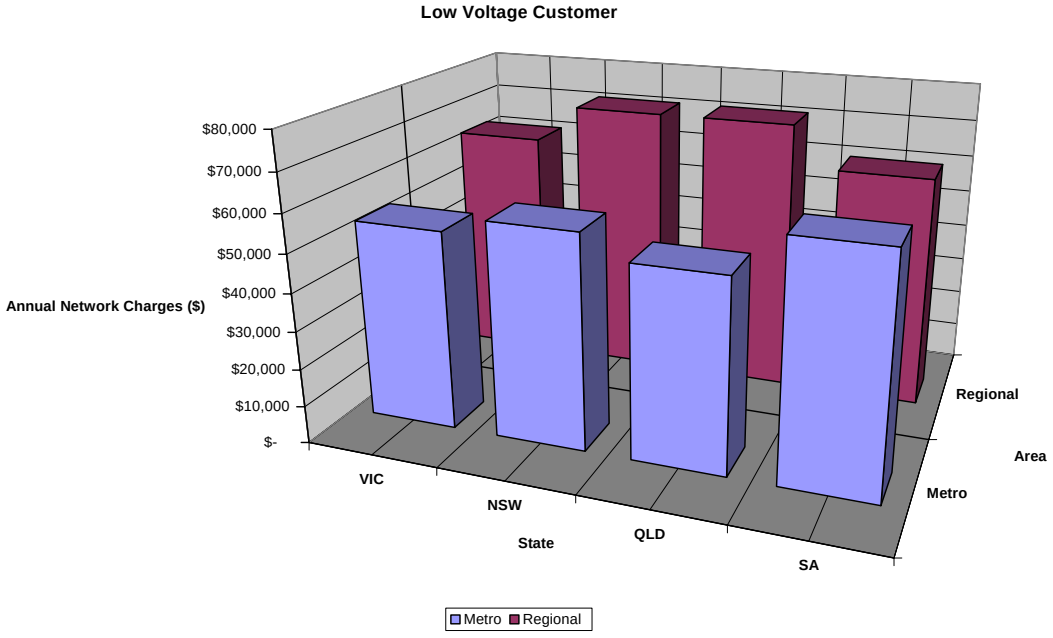
We also emphasise that benefits to customers comprise both price and service and that service standards for regional networks tend to be more difficult to maintain than for metropolitan networks. Therefore the differentials in net customer outcomes are likely to be greater than just the price differences illustrated below.

[1] The ACT and Tasmania are not included in these illustrations. South Australia, a single distribution network, operates throughout the jurisdiction, thus obviating locational differences in distribution network prices.

Example 1 – Low voltage business customer

A small manufacturing business with annual electricity consumption around 1,400,000 kWh (or 1.4GWh).

Chart 1-1: Illustrative regional and metropolitan electricity network charge differentials



Regional / Metro	Annual Network Charge ($)			
	Vic	NSW	Qld	SA
Regional	63,000	73,000	73,000	62,000
Metro	53,000	57,000	51,000	62,000
Difference ($)	***10,000***	***16,000***	***22,000***	**-**
Difference (%)	***19%***	***28%***	***43%***	**-**

In this example, the impact of being located in a network that serves predominantly regional, rather than metropolitan, customers ranges up to $22,000 per annum or a 43 percent increase over metropolitan network tariffs.

Estimated annual network charges have been calculated by using a business' actual monthly peak consumption, off peak consumption and maximum demand data and applying applicable network tariffs assuming that the business is connected to the following networks.

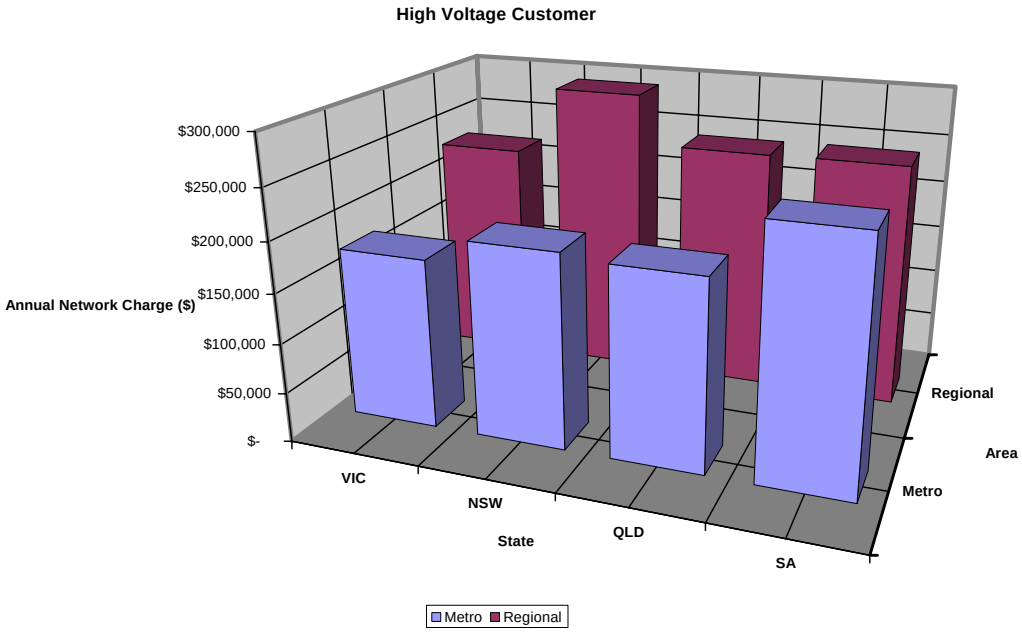
Assumed networks	Victoria	NSW	Queensland	SA
Regional network	Powercor	Country Energy	Ergon Energy	ETSA Utilities
Metropolitan network	CitiPower	Integral Energy	Energex	ETSA Utilities

Appendix E-5 provides more detail on the assumptions and calculations used to derive this example.

Example 2 – High Voltage customer

A larger manufacturing business with an annual electricity consumption of around 9,000,000 kWh (or 9GWh).

Chart 1-2: Illustrative regional and metropolitan electricity network charge differentials



Regional / Metro	Annual Network Charge ($)			
	Vic	NSW	Qld	SA
Regional	226,000	296,000	246,000	247,000
Metro	172,000	196,000	191,000	247,000
Difference ($)	***54,000***	***100,000***	***55,000***	***-***
Difference (%)	***31%***	***51%***	***29%***	***0%***

In this example, the impact of being located in a network that serves predominantly regional, rather than metropolitan, customers ranges up to $100,000 per annum or a 51 percent increase over metropolitan network tariffs.

Estimated annual network charges have been calculated using the same approach and location assumptions as Example 1.

Several factors influence differentials in electricity network prices for specific businesses. For example load, load profile and demand, as well as location[2].

To provide broader illustrations of the differentials, this study collected network cost data from a sample of 10 metropolitan and 17 regional business locations in Victoria, New South Wales, Queensland and South Australia.

The results which are summarised in Section 5 show that rural and regional network prices in the sample are generally higher than metropolitan[3] network prices by the order of 10 percent to 40 percent, according to jurisdiction.

The sample is not of sufficient size to allow a statistical rather than an illustrative correlation of network price with location. Also, businesses generally had different load and demand characteristics, which meant that the sample does not normalise out these influences. For these reasons, we suggest that it is more meaningful to use the data to draw conclusions based on ranges, rather than point estimates, of price differentials.

1.2 Locational cross subsidies are embedded within each distribution network but they are limited

Electricity network costs are not allocated to customers on a precise geographic basis. Rather, most customers of a distribution network share in costs spread over the entire network regardless of customer location ("postage stamp pricing"). Section 4 outlines these intra-network cross subsidies. While most distribution networks do not precisely match regional and metropolitan boundaries in Victoria, Queensland and NSW, they *broadly* align with regional and metropolitan areas, where 'metropolitan' is defined as the area within the bounds of State and Territory capital cities and their immediate surroundings. Hence while intra-network cross subsidies exist, they provide limited locational cross subsidisation in these jurisdictions.

In Victoria and Queensland in particular, other inter-network cross subsidies exist but they are unwinding.

1.3 Many regional NEM customers face greater price differentials as other cross subsidies unwind

Section 4 also outlines where inter-network cross subsidies exist in the NEM that impact regional business network customers. They principally comprise:

- **Victoria's Transmission Equalisation Adjustment (TEA)** – which pre-dated the National Electricity Rules and its predecessor the National Electricity Code. Its purpose was to allow a gradual transition to more cost reflective pricing, not to permanently insulate regional and

[2] Refer to Appendix A for definitions of load, load profile and demand.
[3] By "Metropolitan", we mean within the bounds of the capital city in each State. By "Regional", we mean all other locations.

rural customers from cost reflective pricing. The TEA is being phased out over the period to 2020. Section 1.4 outlines the effect of this on regional customers in Victoria.

- **Victoria's vesting asset revaluation adjustment** – This was a one-off adjustment made at the time of reform in 1994 to mitigate price differentials between distribution areas. Its intent was for regional distribution customers to pay less than efficient economic costs indicated by the original network asset valuations at the time of reform and for metropolitan customers to pay more. The effects of this adjustment will continue to unwind as the original vesting assets are fully written down and/or replaced.

- **Queensland Community Service Obligation ("CSO") arrangements** - Due to its exceptional length and sparse customer density, Ergon Energy's customers face significantly higher network costs than their counterparts located in Energex's distribution area. To alleviate this, Queensland's CSO has the effect of providing an inter-network cross subsidy but does so by a CSO administered in the retail tariffs, *outside* of the regulatory framework. It has to date operated to provide a uniform retail tariff throughout Queensland that over recovers costs from Energex's customers and under recovers cost from Ergon's customers. With the impending introduction of Full Retail Competition ("FRC") to Queensland and the partial sale of the government's energy retail interests, this arrangement is likely to be revised. But how it may be structured and funded in the future is unknown to us at the time of writing.

In addition, **Victoria's Network Tariff Rebate Scheme** operates until 2008 to subsidise retail prices for small businesses and domestic customers of Powercor and SP AusNet's distribution networks. This rebate is in the form of government payment intended to alleviate the impact of small customers being exposed to cost reflective pricing following the introduction of full retail contestability.

1.4 The impact of unwinding Victoria's TEA

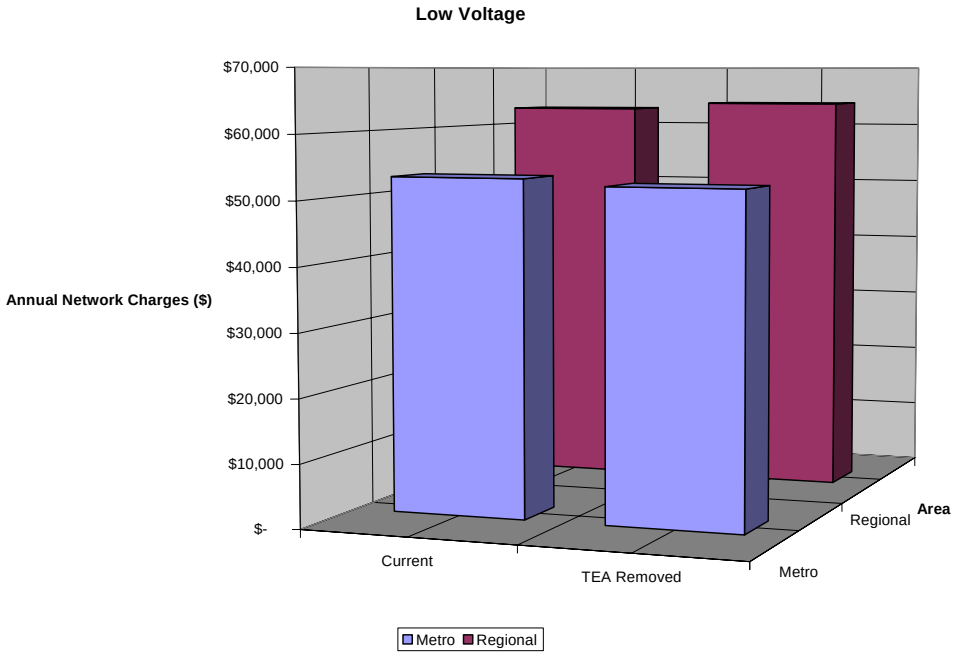
Victoria's TEA is reducing with time and expires in 2020. The following examples illustrate the dollar impact for the two illustrative customers provided in the examples above.

We emphasise that these are illustrative examples. The specific impacts will differ for individual customers according to a range of factors, including the network they may be located in and how the distribution businesses allocate the benefits or costs of the TEA to different customer groups, in their tariff structures. Section 5.1.4 summarises the other assumptions we have used and explains why the costs and benefits in the examples below are not necessarily equal.

Example 3 – Low voltage business customer

A small manufacturing business with annual electricity consumption around 1,400,000 kWh

Chart 1-3: Removal of TEA – illustrative impact on annual network charge



Regional / Metro	Annual Network Charge ($)		
	Current	Without TEA	Difference
Regional	63,000	64,000	*1,000*
Metro	53,000	52,000	*(1000)*
Difference ($)	***10,000***	***12,000***	***2,000***
Difference (%)	***19%***	***23%***	***4%***

For example, regional Victorian business located within Powercor's distribution area:

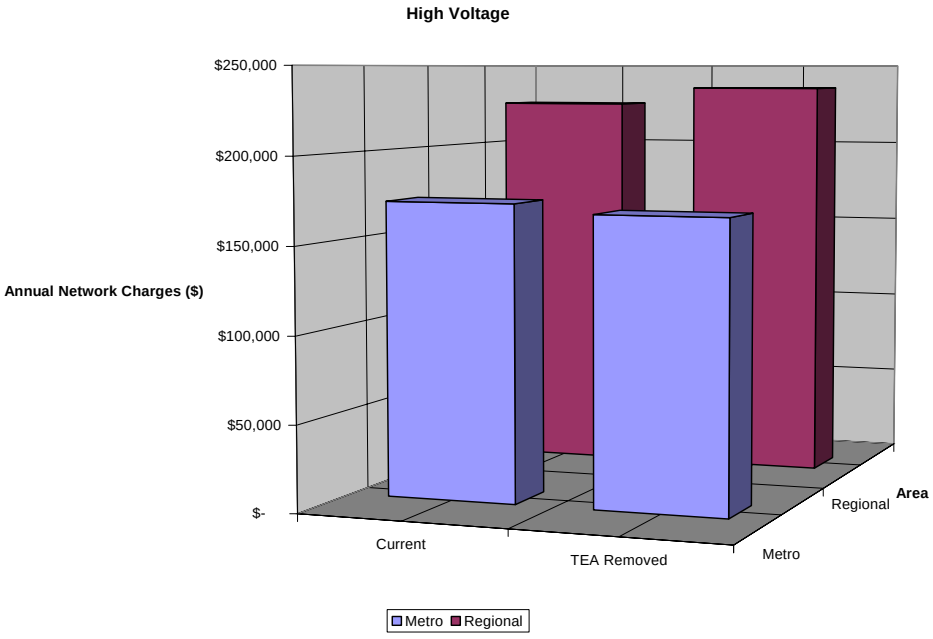
- the removal of the TEA is estimated to increase the annual network charge by $1,000 or 1.6 percent; and
- if that business were located in metropolitan Melbourne within Citipower's distribution area, we estimate a 1.9 percent decrease in its annual network charge of $1,000.

The differential between regional and metropolitan locations in this example is estimated to increase by a further 4 percent with the removal of the TEA.

Example 4 – High voltage business customer

A small manufacturing business with annual electricity consumption around 9,000,000 kWh

Chart 1-4: Removal of TEA – illustrative impact on annual network charge



Regional / Metro	Annual Network Charge ($)		
	Current	Without TEA	Difference
Regional	226,000	236,000	*10,000*
Metro	172,000	167,000	*(5000)*
Difference ($)	***54,000***	***69,000***	***15,000***
Difference (%)	***31%***	***41%***	***10%***

For example, regional Victorian business located within Powercor's distribution area:

- the removal of the TEA is estimated to increase the annual network charge by $10,000 or 4.4 percent; and
- if that business were located in metropolitan Melbourne within Citipower's distribution area, we estimate a 2.9 percent decrease in its annual network charge of $5,000.

The differential between regional and metropolitan locations in this example is estimated to increase by a further 10 percent with the removal of the TEA.

1.5 Line losses and emerging regional pricing issues

The different physical characteristics of regional and metropolitan networks lead to customers served by extended regional networks generally incurring greater costs of "line losses" than their metropolitan counterparts. These costs arise because a proportion of the power fed into a network is generally dissipated by resistance losses. More extended networks necessary to serve regional areas, tend to have greater line losses. While the costs of line losses are passed through to customers in their energy charges, theses costs are nonetheless closely related to network geography.

For example, differentials in distribution loss factors can lead to retail energy costs being up to about 5.4% more for regional businesses in Victoria (who are low voltage customers consuming less than 40GWh pa or with a peak demand of less than 10MW) than for comparable businesses within metropolitan-based distribution regions[4]. Customers also bear transmission loss factors which can lead to further geographic differences in retail energy costs. These differentials are additional to the differentials in network charges described above and the effect of unwinding cross subsidy schemes, such as the TEA in Victoria.

A consequence is that any general increases in energy charges may be magnified for regional customers and further increase the differentials between regional and metropolitan customers.

For example, wholesale energy prices in the NEM recently increased. This is generally considered to be attributable to the effects of the drought and the capacity of generators to access cooling water. Also, the introduction of any carbon trading system that increases energy prices by introducing a cost or carbon could increase differentials.

An illustrative example of the potential additional costs borne by regional businesses is provided below. Assume:

- that a metropolitan located business faces a general increase in energy prices of say $10 per MWh; and
- another business that is identical in all regards except that it is located in a regional area that is subject to a loss factor of say 5% greater than its metropolitan counterpart.

The consequence would be that the regional business would face a price rise of $10.50 per MWh. Accordingly if both businesses had an annual consumption of say 2,000MWh then the regional business would face an increase of $1,000 pa more than that faced by its metropolitan counterpart.

[4] Essential Services Commission of Victoria, Final Decision – Approval of Distribution Loss Factors for the 2007-08 Financial Year, April 2007.

1.6 Options for dealing with the differentials

The analyses set out in this report lead to three options for regional business customers to address these differentials:

- seek change within the network pricing framework;
- change the network pricing framework; or
- seek economic support outside of the regulatory framework.

We summarise these options below.

1.6.1 Seek change within the network pricing framework

The National Electricity Rules do not accommodate inter-network cross subsidies, such as the TEA, which would run contrary to the pricing and policy principles on which they are founded. For the TEA to be prolonged or extended would appear to require a further derogation to, or change in, the National Electricity Rules. These would be a challenging task requiring arguments based on principles of regulatory economics. However, it is difficult to see how such an argument could be sustained and be compatible with principles of efficient cost reflective pricing.

There may be other opportunities for reducing differentials within existing networks. For example, where businesses may make greater use of local or embedded generation, they may avoid network costs. For this to be a viable option, reductions in network prices would need to be sufficiently reflective of avoided costs to provide a practical incentive for customers to invest in generation to provide cheaper overall costs of supply. But this would imply further reducing, not maintaining, of cross subsidies, and the benefits for regional customers could be highly selective. More cost reflective prices could increase rather than reduce network differentials for regional customers who may be sited further away from sources of generation embedded or otherwise. The associated pricing issues and debate that may influence these outcomes are complex and likely to require technical support and knowledge.

1.6.2 Change the network pricing framework

The inclusion of inter-network cross subsidies in the national network pricing mechanisms would require a departure from its principles of efficient cost reflectivity. This would be a fundamental change and would require significant policy reversals by COAG and reversals of approach by the Ministerial Council on Energy and the Australian Energy Markets Commission (AEMC). Section 6 provides further explanation and reasoning for this conclusion. For these reasons, we suggest that this option is unlikely to meet the City of Greater Bendigo's objectives in the foreseeable future.

1.6.3 Seek economic support outside of the regulatory framework

The electricity network pricing mechanism and its associated regulatory framework is concerned with establishing network prices according to economic principles. Its remit does not extend to intervening in market responses to those prices.

Rather, we suggest that in practice policy and market responses to prices lie with market participants and those sectors of government responsible for those markets. For these reasons, we suggest that, where arguments exist for support for specific customer groups (such as regional business customers), bodies such as the MCE and AEMC are less likely to view this as being within their remit, unless there is evidence that the economic principles that guide the price setting rules are inappropriate. This consideration and the analysis set out in this report suggest that:

- the arguments for financial support rest on financial and economic impacts on regional businesses and economies; and

- there are not strong economic arguments to suggest that setting prices that are broadly based on efficient costs is an inappropriate approach to pricing.

Accordingly, support to assist regional business customers to respond to cost and pricing differentials is more likely to be successfully sought from outside, than within, the regulatory price setting mechanism.

Further support for this conclusion is promoted by our analysis of the precedents for inter-network cross subsidies summarised at Section 1.3:

- we have explained above that the TEA predates and is only accommodated by the National Electricity Rules, by a derogation. An extension of the TEA does not appear to be an option under the current pricing framework;

- the vesting asset adjustment was made by the Victorian government at the time of industry reform. Because the Victorian networks are no longer owned by government, its maintenance or reinstatement is no longer a relevant option in Victoria; and

- the distribution networks in NSW are still owned by government, which could in principle write down asset values to reduce costs and prices to customers of regional networks. However, this would require government as the shareholder, to permanently forego significant revenues, from tariffs or if networks were to be subsequently sold, from sale proceeds.

  This would have the same effect as government providing a CSO except that it would not be focused on specific customer groups within a network. However, if an asset write down was significant, it would put at risk the network's capability to generate sufficient revenue to meet the costs of asset replacement and ongoing network investment. This could lead to a long-term decline of the network and its service standards. Furthermore, it is unlikely that under the National Electricity Rules a regulator would allow government to cross subsidise such an adjustment by writing up asset values in other government owned networks to recover amounts greater than efficient cost, from the customers of those networks.

This leaves the Queensland CSO and Victoria's Network Tariff Rebate schemes as relevant precedents.

Both of these mechanisms are CSOs that operate outside of, and are not dependent on, the regulatory network pricing framework. While the Queensland CSOs' historic implementation has been criticised because of its distortionary effects on efficient retail pricing, there is a wide variety of mechanisms by which a CSO could be implemented, which do not necessarily distort competitive prices.

On the basis of these considerations, in Section 6 we outline a Regional Network Fund ("RNF") which could allocate regional development assistance from government to offset the adverse regional effects of network pricing disparities. Potentially, the RNF could provide payment in two forms:

- one-off contributions to network expenditure that improve regional customer outcomes; and

- tariff support payments to offset the differential in regional and metropolitan network supply costs.

We suggest that government support would be justified in terms of the positive regional economic impacts, avoided costs, or social and environmental benefits. This would provide a business case and justification for support that would be in the public interest and provide a net sum gain to the economy, but without directly imposing additional costs on other customer groups.

We also observe that a key economic development strategy for many regional municipalities is to focus on business retention and attraction. In addition, State Governments have a range of strategies to grow regional areas and their economies. However, it is not a role of the current model of economic regulation of electricity networks to address such development and attraction strategies or to address broader regional economy wide impacts and social costs. Indeed the emphasis economic regulation places on network cost reflective pricing may create imperatives for additional regional economic development support where these costs may have broader impacts that could be adverse to regional economic development policy.

This suggests that:

- Governments may need to be cognisant of the network price differentials between regional and metropolitan areas in developing regional economic and social development policies or programs; and

- the regulatory framework needs to focus on developing network prices that provide incentives for appropriate investment in localised, embedded generation and demand side management technologies. This could assist regional customers to manage current cost differentials which may be further accentuated by the impact of carbon pricing on energy costs.

We discuss the justification for government support in more detail in Section 6.

1.7 How to move forward

The actions to progress the options outlined above by the City of Greater Bendigo or other stakeholders might include:

- starting a process of canvassing whether there may be in-principle support for a Regional Network Fund from jurisdictional energy and regional development agencies in Victoria, New South Wales and Queensland. This would include establishing the information and decision criteria that governments may require to move forward;

- starting a process to canvass network businesses with regional customers in Victoria, New South Wales and Queensland, for the likely degree of support for such a scheme. Combined approaches on issues from both customers and businesses can carry significantly greater weight and influence with governments and regulators;

- undertaking further work possibly in conjunction with other local governments or stakeholders to establish the economic effects or impacts of higher regional network prices. This study and its predecessors commissioned by the City of Greater Bendigo, have established that pricing differentials exist. However, the case for support may be more robust if the economic and financial *impacts* that might justify financial or economic support can be evidenced;

- evidence of broader economic detriment from higher network prices would be especially important for any proposal for tariff support, where the financial support required may be very significant but net sum gains from specific payments more difficult to demonstrate. The benefits of network expenditure support could be evidenced by a range of case studies that might clearly demonstrate where investment in local economies has been avoided because of higher regional network infrastructure costs. We also suggest that any body of evidence of regional disadvantage should consider service standards as well as cost differentials. Reviewing prices and costs without regard to service standards holds risks of longer-term service standard decline or network under investment. In the limited sample we interviewed, 30 percent of respondents indicated that a marginal increase in service standards would be more valuable than marginal reductions in price. This proportion could increase in the future if businesses continue to become more dependent on technology to be competitive and efficient; and

- developing a more detailed practical implementation outline or 'business plan' for the scheme once the body of evidence that would satisfy governments' decision criteria and the in-principle support of governments and stakeholders have been established.

In the meantime, none of this activity would preclude regional business customers continuing to participate in the regulatory debate by participating in the public consultation processes run by the regulatory bodies on issues likely to affect them, including service standards, locational transmission pricing and incentives for embedded generation. But these issues may be of concern to all customers but regional customers are likely to have specific interests and requirements. We suggest that, with the advent of the Australian Energy Regulator (AER), the technical substance of these processes may be no more accessible to the well informed lay person than it has been in the past. To this end, peak bodies representing regional businesses may need to access specialist advice and support such as that facilitated by the National

Electricity Consumers Panel. This would be most effectively conducted through pro-active planning for anticipated regulatory issues, to allow timely responses when the issues arise for public consultation.

2 Introduction

2.1 Scope – terms of reference

Businesses that operate in or are considering investment in rural and regional Australia can face electricity network costs that are significantly greater than those of their metropolitan counterparts and competitors. These cost differentials have been established by reforms to Australia's electricity supply industry that include the implementation of National Competition Policy and the creation of the National Electricity Market ("NEM").

While some Australian governments have put in place measures to mitigate the resulting electricity network price differentials, their effects are now unwinding or may not provide significant long-term certainty. Energy supply is critically important to economic and social development. The consequences of geographic pricing differentials between regional and metropolitan regions include risks to:

- economic development in regional Australia; and
- Australia's competitiveness as an investment location for businesses that require access to regional sources of supply and markets.

The Bendigo Manufacturing Group and the City of Greater Bendigo have campaigned for equity in network charges for non-metropolitan distribution regions since 2001. Historically, this work originated from the concerns of businesses located in regional Victoria. (For example see "Central Victorian Demand Tariff Energy Project"[5].)

The Bendigo Manufacturing Group and the City of Greater Bendigo believe that electricity network cost differentials are a national issue. Not only are regional businesses at risk, but many businesses that invest in regional Australia operate nationally, not separately in individual jurisdictions.

Also, recent changes in jurisdiction, such as the establishment of the Australian Energy Market Commission ("AEMC") and the Australian Energy Regulator ("AER"), and recent endorsements of the Australian Energy Market Agreement ("AEMA") by the Commonwealth and Jurisdictions and Territories, seek to provide a national framework for energy market regulation. Accordingly, the Bendigo Manufacturing Council and the City of Greater Bendigo:

- seek to pursue these issues on a national not a local basis; and
- have obtained funding from the National Consumer's Electricity Advocacy Panel to undertake a project with an objective of effecting change to reduce the differentials between regional and metropolitan electricity costs and their inhibiting effects on regional economic development.

[5] Central Victorian Demand Tariff Energy Project City of Greater Bendigo, September 2005
http://www.bendigo.vic.gov.au/Page/Page.asp?Page_Id=1194

To assist with these objectives, the City of Greater Bendigo has engaged KPMG to provide it with an independent report that:

- provides an overview of the distribution and transmission networks in the interconnected NEM;
- explains in detail the network subsidy/rebate or related schemes that have been introduced and, where relevant, the reasons why such schemes are being phased out or are for designated periods only;
- validates details of the impact of the cessation of network subsidies or rebates or related schemes, on regional large business customers;
- validates details of the current inequities in network costs (including loss factors) for large business electricity consumers based in regional areas, compared to metropolitan distribution areas;
- sets out reasons for and against the establishment of an ongoing network subsidy/rebate scheme within the NEM to address the inequities in network costs between regional and metropolitan electricity consumers; and
- develops a strategy and policy for the provision of an ongoing network subsidy/rebate scheme in the context of economic development for Australia's regional areas.

This document provides that report. The following sections and appendices:

- describe the background to the NEM and how its price setting mechanisms can lead to differentials in price between regional and metropolitan areas;
- present evidence gathered as part of this study, that illustrates and analyses the effects of these price differentials; and
- outline a strategy to offset network costs for regional businesses.

This report is accompanied by a discussion paper that summarises the key features and findings of this report, to assist the City of Greater Bendigo with its advocacy for a national scheme to reduce the differential in electricity network costs between metropolitan and regional business consumers.

2.2 Disclaimer

2.2.1 Inherent Limitations

Section 1.1 to this report outlines its basis of preparation. The procedures outlined in Section 1.1 do not constitute an audit.

The findings in this report reflect a perception of electricity network costs incurred by businesses, but only to the extent of the sample surveyed, being the representative sample approved by the City of Greater Bendigo. Any projection to the wider population of businesses as a whole is subject to the level of bias in the method of sample selection.

No warranty of completeness, accuracy or reliability is given in relation to the statements and representations made by, and the information and documentation provided by the stakeholders consulted as part of the process.

KPMG has indicated within this report the sources of the information provided. We have not sought to independently verify those sources unless otherwise noted within the report.

KPMG is under no obligation in any circumstance to update this report, in either oral or written form, for events occurring after the report has been issued in final form.

The findings in this report have been formed on the above basis.

2.2.2 Third Party Reliance

This report is solely for the purpose set out in the Introduction to this report and for City of Greater Bendigo's information.

This report has been prepared at the request of the City of Greater Bendigo in accordance with the terms of KPMG's contract dated 2 November 2006. Other than our responsibility to the City of Greater Bendigo, neither KPMG nor any member or employee of KPMG undertakes responsibility arising in any way from reliance placed by a third party on this report. Any reliance placed is that party's sole responsibility.

3 Background

This section of the report and its associated appendices, presents high-level backgrounds to:

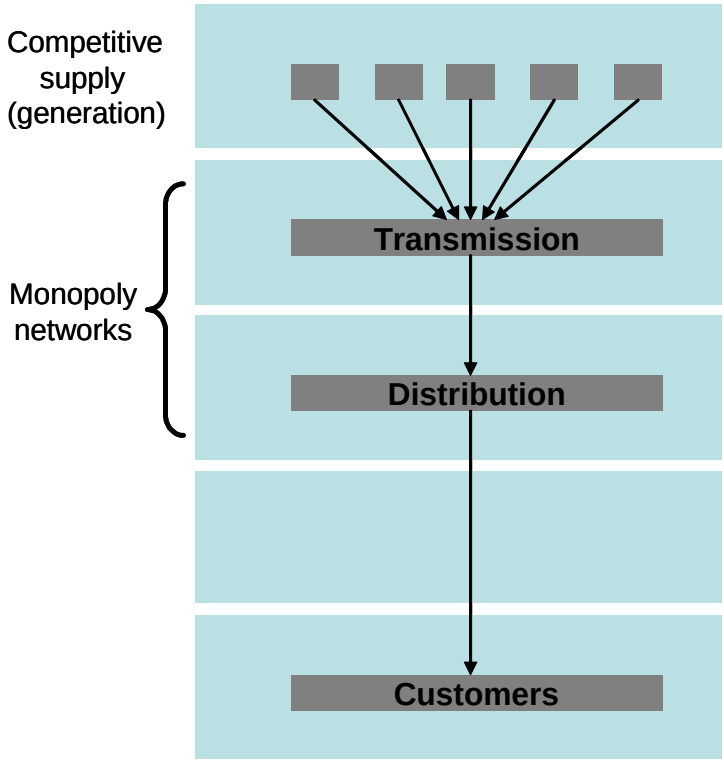
- the electricity industry in Australia;
- the components of an electricity bill; and
- the institutional and regulatory structures of the National Electricity Market (NEM).

We emphasise that this section of the report intends to provide overviews sufficient to provide context for its subsequent findings rather than a comprehensive description of the characteristics of the NEM.

3.1 The electricity supply industry structure – an overview

This section briefly outlines the key sectors of the electricity supply industry in the NEM and how networks interact with the other sectors.

Figure 3-1: Schematic structure of electricity industry



Generation

Generators which may be government or privately owned, produce and sell electricity.

The National Electricity Market Management Company (NEMMCO)

In its role as system operator, NEMMCO is responsible for managing the dispatch of electricity by generators into the networks, for balancing physical supply and demand and for maintaining security of supply. NEMMCO is jointly owned by the Commonwealth Government and the jurisdictions that participate in the NEM.

Transmission networks

Transmission networks:

- transport power from generators to distribution networks or in some cases high voltage customers that are connected directly to the transmission network;
- are the higher voltage (normally greater than 66kV) arterial lines of supply[6]; and
- may cross state and territory boundaries. Such lines are generally referred to as "interconnectors" or "interconnects".

Distribution networks

Distribution networks are the lower voltage, higher density networks that link the vast majority of customers to transmission supplies[7].

Almost all distribution networks are entirely contained within a single jurisdiction.

Government or privately owned companies own and are responsible for maintaining and operating specifically defined transmission and distribution networks. Appendices B and C list the principal NEM networks, their geographic location and coverage.

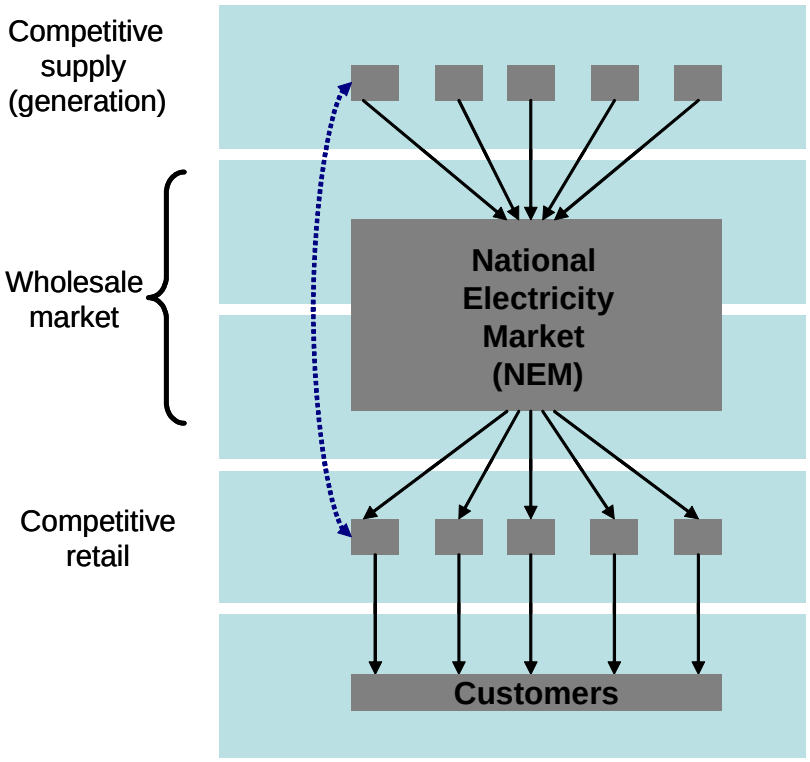
[6] A transmission network is defined by the National Electricity Rules as "A network within any participating jurisdiction operating at nominal voltages of 220 kV and above plus: (a) any part of a network operating at nominal voltages between 66 kV and 220 kV that operates in parallel to and provides support to the higher voltage transmission network; (b) any part of a network operating at nominal voltages between 66 kV and 220 kV that is not referred to in paragraph (a) but is deemed by the Australia Energy Regulator to be part of the transmission network." (National Electricity Rules, Version 11, 30 November 2006, page 814)

[7] A distribution network is defined by the National Electricity Rules as "A network which is not a transmission network." (National Electricity Rules, Version 11, 30 November 2006, page 758)

3.1.1 Market components

In addition to the physical assets required to supply electricity, other entities participate in financial markets in the electricity supply industry. These are illustrated in Figure 3-2. Supporting descriptions are provided below.

Figure 3-2: Structure of a competitive electricity market



Competition has been introduced in electricity generation through the unbundling of generation from transmission and widening access to the transmission network. Both the transmission and distribution networks remain monopolies. Competition in these sectors would result in uneconomic duplication of physical networks and may in any event be impractical on a broad scale.

The wholesale spot market

Financial markets co-exist with the physical markets. The spot price of electricity is a function of supply and demand and the marginal cost of generation. Each of these factors can vary significantly within the day and across the year. Generators and retailers participate in a wholesale spot market for the NEM, which NEMMCO also manages. Generators and retailers can also manage risk in the spot market by entering into off-market hedging or insurance contracts directly with one another.

Retailers

Retailers provide customers with access to the market for competitive supply. The key roles of retailers include:

- managing the financial risks of purchasing energy on the wholesale market which can have prices which vary significantly over the course of a day or between seasons, and selling it to customers at agreed prices;
- metering; and
- billing including collecting network and other charges (this is explained in more detail in Section 3.2).

Retailing is now fully competitive in ACT, NSW, SA and Victoria. All small customers will have access to competitive retail markets in Queensland by July 2007 and in Tasmania by July 2010. However, experience has shown that it can take some time before the market develops sufficiently for competition to become effective.

3.2 The electricity bill explained

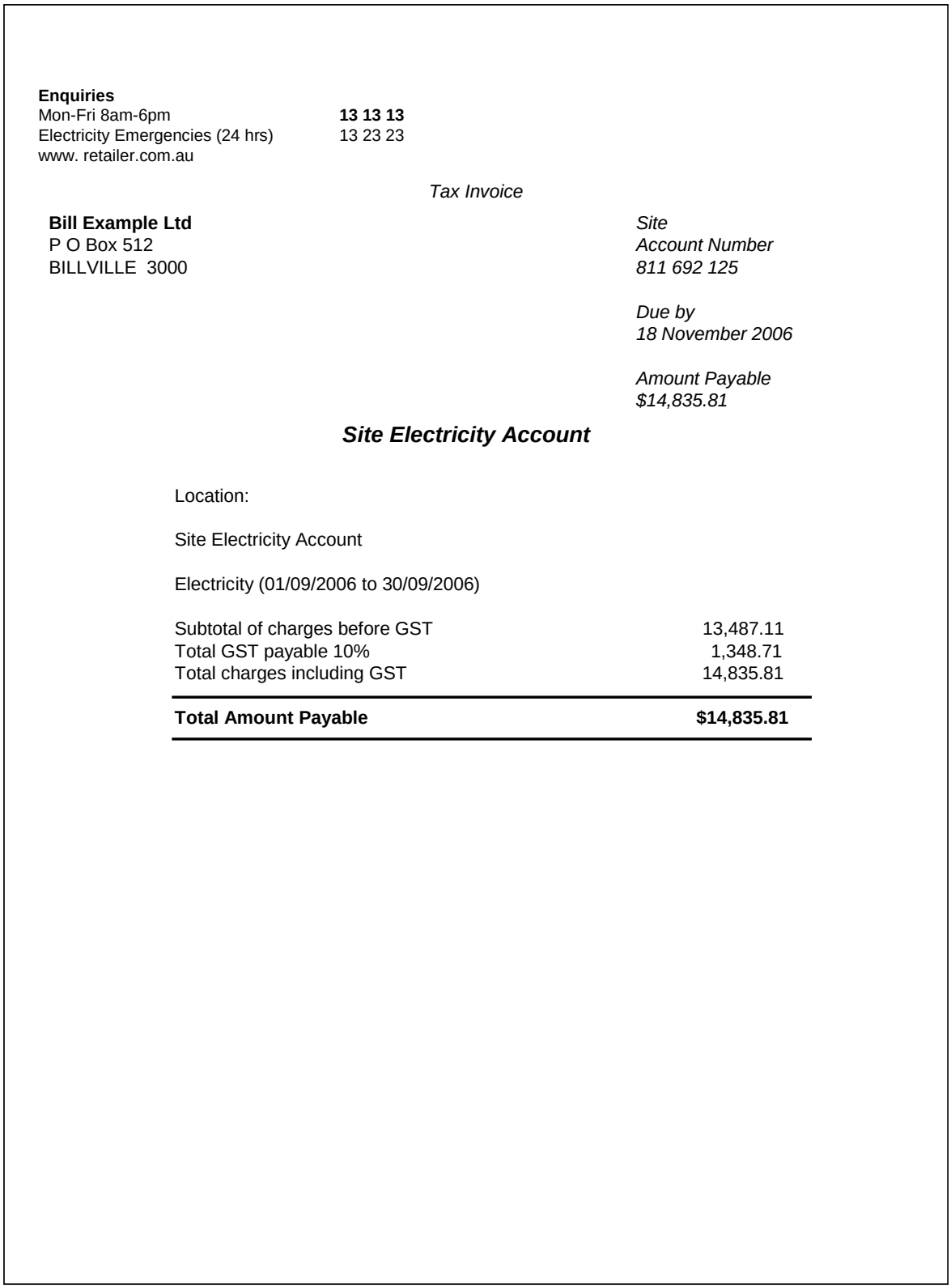
Figure 3-3 illustrates a typical electricity bill. We outline its components to illustrate the context of network charges.

The electricity bill is typically made up of several parts:

- energy charges;
- network charges;
- market or system operator charges; and
- metering and other charges.

A retailer purchases electricity from the wholesale electricity market to sell to retail customers. The retailer also normally passes through the other costs outlined above. An electricity bill for a commercial customer normally shows the breakdown of these costs so that the customer may understand the allocation of the total payment to different segments of the supply chain.

Figure 3-3: An example of an electricity bill



Enquiries
Mon-Fri 8am-6pm **13 13 13**
Electricity Emergencies (24 hrs) 13 23 23
www. retailer.com.au

Tax Invoice

Bill Example Ltd
P O Box 512
BILLVILLE 3000

Site
Account Number
811 692 125

Due by
18 November 2006

Amount Payable
$14,835.81

Site Electricity Account

Location:

Site Electricity Account

Electricity (01/09/2006 to 30/09/2006)

Subtotal of charges before GST	13,487.11
Total GST payable 10%	1,348.71
Total charges including GST	14,835.81
Total Amount Payable	**$14,835.81**

Electricity Analysis Report

Account Number: 839 322 540
Name: Bill Example Ltd
Supply Address: Bill St, Billville 3500
Supply Period: 1 September 2006 to 30 September 2006 – 30 days
Date of Issue: 10 October 2006
NMI: 4103317236-2

ENERGY TIME OF USE BREAKDOWN		
Off Peak	125,791 kWh	53.02%
Peak	111,472 kWh	46.98%
TOTAL ENERGY	**237,263 kWh**	

DEMAND DETAILS
Maximum Chargeable Demands

All Times	442,673 kVA on 5.09.2006 @ 16:00:00

AVERAGE DAILY CONSUMPTION	BILL DAYS THIS PERIOD
7,909 kWh	30

Load Profile

Date	Consumption	Max Demand
Oct 05	238,660 kWh	460 kVA
Nov 05	241,191 kWh	460 kVA
Dec 05	246,445 kWh	4793kVA
Jan 06	255,873 kWh	588 kVA
Feb 06	221,886 kWh	463 kVA
Mar 06	255,341 kWh	480 kVA
Apr 06	226,744 kWh	460 kVA
May 06	233,984 kWh	415 kVA
Jun 06	221,190 kWh	491 kVA
Jul 06	236,577 kWh	412 kVA
Aug 06	226,687 kWh	413 kVA
Sep 06	237,263 kWh	443 kVA

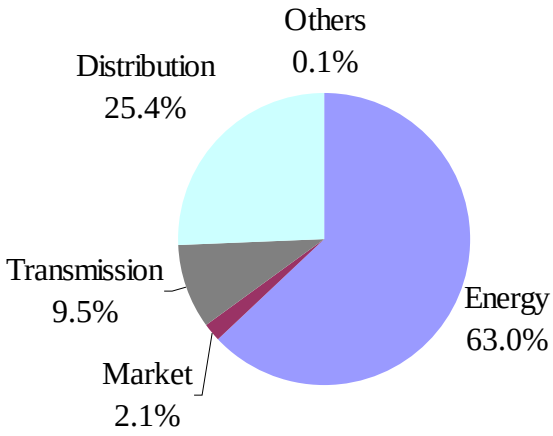
Electricity Usage Report

Account Number: 839 322 540
Name: Bill Example Ltd
Supply Address: Bill St, Billville 3500
Supply Period: 1 September 2006 to 30 September 2006 – 30 days
Date of Issue: 10 October 2006
NMI: 4103317236-2

Transmission Loss Factor (TLF): 0.993000
Distribution Loss Factor (DLF): 1.037900

CHARGES	QUANTITY	X	RATE*	X	TLF	X	DLF	=	TOTAL
Energy Charges									
Peak (M-F)	111,472,000 kWh		5.0560 c/ kWh		0.993000		1.037900		$5,808.68
All Other Times	125,791,000 kWh		2.2620 c/ kWh		0.993000		1.037900		$2,932.56
Total Energy Charges	**237,263,000 kWh**								**$8,741.24**
Network Charges									
DUOS for Peak	84,391,000 kWh		1.3070 c/ kWh						$1,102.99
DUOS for Off Peak	152,872,000 kWh		0.7410 c/kWh						$1,132.78
DUOS for Demand Charges	576,310 kVA		3.8883 $/ kVA						$2,240.87
Total Network Charges									**$4,476.64**
Market Charges									
NEM Administration	237,263,000 kWh		0.0356 c/ kWh				1.037900		$87.67
NEM Ancillary Services	237,263,000 kWh		0.0507 c/ kWh				1.037900		$124.85
Total Market Charges									**$212.52**
Other Charges									
Meter Provision	30 Days		1.8904 $/Meter/Day						$56.71
Renewable Energy Certificates	237,263,000 kWh						1.0376900		$0.00
Total Other Charges									**$56.71**
TOTAL ELECTRICITY BEFORE GST									**$13,487.11**

Figure 3-4: Illustrative breakdown of the components of a business customer's electricity bill



The analysis for individual customers will vary according to things such as total load, demand and daily and seasonal load profiles.

Energy charges and loss factors

The average electricity customer is charged usually monthly or quarterly for the consumption of electricity. This amount is a function of the *price* (cents per kWh) and the *amount* of energy (kWh) consumed.

The retail end of the electricity supply chain is generally competitive for business customers. Customers may opt for competitive prices by negotiating with retailers or choosing or negotiating a tariff plan appropriate to their consumption pattern. For example, there are 'seasonal time of use' tariffs which offer peak and off-peak rates during the day or which varies with the month concerned.

There is a difference between the amount of electricity supplied by generators and the amount of electricity actually received by customers. Resistance in the physical network means that customers inevitably receive less electricity than generators dispatch. The market pays generators for the energy they sell. But because customers receive less electricity than the amounts sold into the market, generators must sell sufficient electricity to satisfy both customer demand and the network resistance losses.

This means that, if customers only paid for the electricity they actually receive, there would be a shortfall between the revenues collected by the wholesale market from customers and the amounts payable by the wholesale market to generators. To make good the shortfall, the revenues collected from customers are multiplied by loss factors comprising:

- a distribution loss factor (DLF); and

- a transmission loss factor (TLF)

specific to each network.

For distribution networks, a standard loss factor is applied to all customers within the network. Resistance losses are largely proportional to the length of line electricity travels along. Because some customers may be at the end of very long lines and others not, the DLFs provide cross-subsidies within each distribution network, with those closest to points of connection between the distribution and transmission networks tending to bear the costs of cross subsidising those customers located further afield.

Transmission loss factors are based on similar principles. However, they differ in that:

- they are measured as marginal changes relative to a load weighted central point of consumption on the network (a regional node). Where a connection point may be closer to a principal source of generation than the regional node, a loss factor of less than 1, which effectively decreases the bill, can result; and

- they tend to be but are not necessarily less than distribution loss factors. While lengthy transmission lines can give rise to high loss factors, this can be mitigated by the higher voltage of transmission networks, which lessens the effects of the resistance losses. Also higher voltage transmission may be more efficiently engineered than some distribution assets. Distribution, but not transmission, loss factors may need to take into account other contributors to energy losses, such as theft and customer metering or estimation errors.

Loss factors are standard measures albeit ones which are reviewed annually by NEMMCO. The National Electricity Rules include processes for attributing the financial gains and losses arising from the differences between actual network losses and those assumed by the loss factors.

Network charges

The total cost for network charges is collected by the retailer and passed through to the local network supplier in exchange for the use of the network.

Network charges comprise both transmission and distribution charges, more commonly known as:

- Transmission use of system charges (TUoS); and

- Distribution use of system charges (DUoS).

As both the distribution and transmission segments are not subject to competition, the charges payable for the use of these monopoly assets are regulated. We outline the regulatory

framework in Section 3.3. It is a mandatory requirement for the distribution network service provider (DNSP) to publish annual TUoS and DUoS charges, or as required by the regulator[8].

In most jurisdictions, transmission charges may not be disclosed on retailers' bills separately. In such cases, they are combined with distribution charges and shown as network charges.

Market or system operator charges

Market charges, also known as system operator charges, are the costs incurred for the provision of system operations and ancillary services by NEMMCO. Ancillary services are crucial to maintaining viable power system operation and encompasses activities such as automatic generation control and system restart.

The rates applicable are determined and published annually by NEMMCO.

Metering and other charges

Other charges shown in the bill cover activities such as billing and meter reading by retailers. This amount is usually a small proportion of the total bill.

3.3 Institutional and regulatory framework

Over the past decade and more, wide-ranging reforms have been introduced to the industry with the aim of making it more consistent across jurisdictions and introducing more competition to enhance economic performance. These reforms have resulted in the creation of the NEM that encompasses the electricity supply industry in the ACT, New South Wales, South Australia, Queensland, Tasmania and Victoria. While separate to the interconnected NEM, Western Australia's industry has also recently undergone significant market reform with similar broad objectives of improving economic efficiency.

Section 3.3.1 describes the milestone events which have helped shape the NEM.

3.3.1 Brief history of reform

Historical context

The present electricity supply industry is the result of more than a decade of major restructuring. Traditionally, the four components of generation, transmission, distribution and retailing were operated by vertically-integrated entities. Although the extent of integration varied across jurisdictions, the consequent lack of competition led to risks of inefficiencies, especially when the entire production chain is performed by a single, monopoly business. The repercussions of

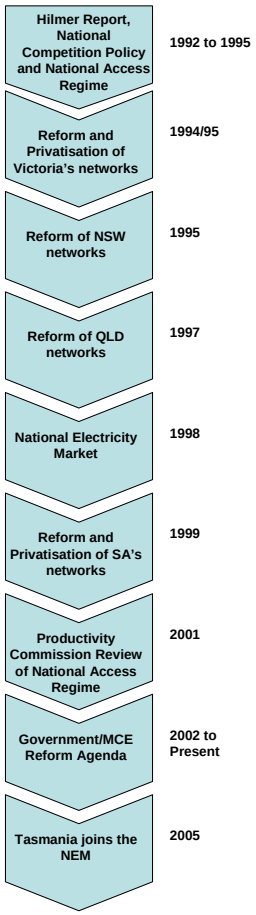
[8] National Electricity Rules, Version 12, 4 January 2007, page 419

being shielded from competition were that there were limited incentives for efficiency and electricity prices were high in comparison to international benchmarks[9].

Separate electricity supply industries historically existed in each jurisdiction to take advantage of their various energy resources – brown and black coal, gas and hydroelectricity. The population of Australia was, and still remains, largely concentrated in the coastal jurisdiction capitals and there was little incentive to construct long networks to connect these population centres[10]. Each jurisdiction had little need to rely on the other jurisdictions for energy.

However, the cost of supply varied according to the resources in each jurisdiction and the physical and operating characteristics of their networks. Consequently, the cost of electricity supply differed between the jurisdictions and there were no mechanisms to match supply and demand on an efficient, national basis.

Figure 3-5: Reform timeline



[9] ACCC, The Utility Congress, *"Reforming Australia's Electricity Market"*, September 2002, page 2
[10] http://www.worldenergy.org/wec-geis/publications/reports/emd/status/australia/default.asp

Need for structural and legislative changes

In May 1990, the Industry Commission[11] undertook a detailed inquiry into the national electricity and gas industries and acknowledged that cross subsidies existed between different classes of users, and between urban and country users. The Commission recommended that structural changes be implemented to increase competition and enhance efficiency[12], including separating the ownership of generation, transmission and distribution assets, and privatising generation and distribution assets.

Following the Industry Commission's report, the Hilmer Committee was set up in 1992 to advise on the appropriate changes to competition law set out in the *Trade Practices Act (TPA) 1974* required to deal with the application of competition policy principles. The Hilmer Committee suggested that the TPA was insufficient to deal with the access to infrastructure in vertically separated monopolies, that competition policy would demand.

In 1995, the Commonwealth and Jurisdiction Governments implemented the National Competition Policy (NCP) which was overseen by the National Competition Council (NCC), an independent policy advisory body.

The national access regime – Part IIIA of the Trade Practices Act 1974

Under NCP, national access arrangements were put into place to provide fair access to certain infrastructure services. These arrangements required owners to provide access to essential infrastructure services on 'reasonable' terms and conditions in cases where infrastructure duplication would be uneconomically feasible[13]. This was to prevent owners of essential monopoly infrastructure exerting monopoly power by for example, denying access to their facilities or charging unreasonable prices for their services, all of which could inhibit competition and be detrimental to the economy and community.

The national access regime as it applies to the electricity industry is set out at *Part IIIA* of the *Trade Practices Act 1974*[14], which is the major source of competition legislation in Australia. *Part IIIA* provides three access routes to "covered" infrastructure such as electricity networks.

[11] Amalgamated into the Productivity Commission in 1996 together with Bureau of Industry Economics and Economic Planning Advisory Commission.
[12] IC, Energy Generation and Distribution, Industry Commission Inquiry Report, May 1991. http://www.pc.gov.au/ic/inquiry/11energy/finalreport/index.html
[13] Productivity Commission, Review of the National Access Regime, Report no. 17, 2001
[14] Note: A different Part XIB specifically deals with access to telecommunication assets.

Access under the national access regime

- *Declaration* – By having a service declared, an access seeker has the right to negotiate with the service provider, with provision for arbitration if negotiations are unsuccessful.
- *Certification* – By having a service certified as effective, access may be granted through an industry-specific regime applicable to the service.
- *Undertaking* – Access may be provided under the terms and conditions specified in an undertaking from the service provider, which have been accepted and registered by the Australian Competition and Consumer Commission (ACCC).

Source: Productivity Commission, *Review of the National Access Regime*, 2001

The national access regime is a cornerstone of regulatory framework which determines prices and other terms and conditions of access to electricity networks in the NEM. We explain below how this framework was implemented and has evolved.

Wave of reforms

In 1994, Victoria started to disaggregate and privatise the formerly vertically integrated, state owned electricity commission. NSW and Queensland followed suit by disaggregating (but not privatising) their electricity supply industries in 1995 and 1997 respectively. At about this time, Tasmania disaggregated but did not privatise its electricity supply industry and, in 1999, South Australia both reformed and privatised its electricity supply industry.

National Electricity Market.

In December 1998, the National Electricity Market (NEM) came into being.

Prior to the NEM becoming operational, NEMMCO was formed with responsibilities for implementing and subsequently administering and operating the NEM. These latter responsibilities include systems operation and wholesale market administration.

The NEM provided a consistent framework for the economic regulation of electricity networks by:

- each participating jurisdiction enacting legislation to implement a jurisdictional access regime, each of which adopted the National Electricity Code (the Code) to provide the detail of the regime's operations. In particular, Chapter 6 of the Code set out network pricing principles; and
- the National Competition Council certifying the jurisdictional access regimes based on adopting the Code as being "effective" under *Part IIIA* of the *Trade Practices Act*.

Each of the jurisdictional access regimes was administered by a jurisdictional regulator, such as Victoria's Essential Services Commission. Responsibility for administering access regimes for the majority of transmission networks lay with the ACCC. These regulators were also responsible for determining some terms and conditions of access, including prices and service standards.

The National Electricity Code (and its successor the National Electricity Rules) were critical to determining how the NEM operates, including the network access regime. The ACCC, in fulfilling its general responsibility for administering the Trade Practices Act, was responsible for authorising the Code and proposed changes to it.

The National Electricity Code Administrator (NECA) was responsible for administering the Code and changes to it. With the advent of the more recent reforms described below, NECA has now been dissolved.

However, notwithstanding the intention to establish a national market and a nationally consistent regulatory framework, the use of jurisdictional access regimes led to a diverse range of institutions being responsible for policy and regulation across the NEM. This is illustrated by Table 3-1 below.

Table 3-1: Policy and regulation arrangements – recent history

	NEM							
	ACT	**NSW**	**SA**	**TAS**	**QLD**	**VIC**	**NT**	**WA**
Transmission								
Govt. Policy	Territory	State	State	State	State	State	Territory	State
Regulation	←——ACCC/AER——→			OTTER	←— ACCC/AER—→		NTUC	ERA
Distribution & Retail								
Govt. Policy	Territory	State	State	State	State	State	Territory	State
Regulation	ICRC	IPART	ESCOSA	OTTER	QCA	ESC	NTUC	ERA
FRC introduced	Yes	Yes	Yes	No	No	Yes	No	No

Table 3-2: Jurisdictional regulators

Jurisdiction within NEM	**Regulator**
ACT	Independent Competition and Regulatory Commission (ICRC)
New South Wales	Independent Pricing and Regulatory Tribunal (IPART)
Queensland	Queensland Competition Authority (QCA)
SA	Essential Services Commission of South Australia (ESCOSA)
Tasmania	Office of the Tasmanian Energy Regulator (OTTER)
Victoria	Essential Services Commission (ESC)
Jurisdiction not within NEM	**Regulator**
Northern Territory	Northern Territory Utilities Commission (NTUC)
WA	Economic Regulation Authority (ERA)

Also see Appendix A for an explanation of acronyms.

COAG Review of Energy Markets or "the Parer Report"

Despite the introduction of the reforms to the electricity supply industry outlined above and parallel reforms to the national gas supply industry, the extent and nature of reform differed between jurisdictions. The institutional framework was complex and there were serious concerns about the efficacy of progress towards the national energy market.

Accordingly in 2001, the Council of Australian Governments (COAG) both endorsed the need for a national energy policy and commissioned an independent review of the strategic direction for the stationery energy sector. The resulting report "Towards a truly national and efficient energy market" ("the Parer report") was published in late 2002.[15] It concluded that the reforms in the electricity and gas sectors had delivered significant benefits but serious deficiencies remained. It provided wide ranging recommendations for how to address these deficiencies for both the gas and electricity markets. Among many other matters, Chapter 9 of the report considered rural and regional issues. It outlined a number of the then current jurisdictional policy initiatives to equalise prices between urban and regional areas and referred to a submission by the City of Greater Bendigo that "energy intensive business experienced significant increases in power costs from 2000 to 2001 and pay among the highest charges within Australia". The report's recommendations did not address regional/metropolitan network pricing disparities per se. Rather, it addressed broader issues that may impact on providing overall more efficient energy prices.

For example, it highlighted that generation is often located in regional areas but the current pricing arrangements do not encourage energy intensive industries to locate close to sources of generation or, by the same token, provide incentives for renewable generation to be located in regional and rural areas.

The report recommended that reforms be made to transmission pricing arrangements with the effect of providing customers with better access to more efficient energy prices that might be

[15] http://www.mce.gov.au/assets/documents/mceinternet/FinalReport20December20022005060212463l%2Epdf

sourced from throughout the NEM. The proposed solutions for addressing these issues (such as Financial Transmission Rights) are complex and include steps to more closely align incentives for transmission investment with energy prices. However, a key point is that a thrust of the recommendations was to increase the cost reflectivity of transmission pricing to encourage more efficient access to energy sources. For example, energy intensive customers locating more closely to sources of generation or for new sources of generation (such as renewables) to be located more closely to regional customers.

The Parer Report also found that:

> *"The energy sector governance arrangements are confused, there is excessive regulation and perceptions of conflict of interest."*[16]

It referred to:

- inconsistency of jurisdictional regulation;
- perceptions of conflict of interest where some governments own and regulate assets as well as set energy policy;
- overlaps in responsibility between different institutional bodies;
- lengthy and inadequate processes for managing changes to the Code; and
- potential perverse incentives from insufficiently focused regulation.

The Parer Report pointed out that these factors and the associated risks of uncertainty ultimately result in increased costs of investment that are passed through to customers.

To respond to these issues, the Parer Report recommended:

- the creation of a National Energy Regulator;
- improving the processes for amending the National Electricity Code;
- greater input by NEMMCO to Code changes;
- using the Ministerial Council on Energy to provide a common approach to policy;
- addressing concerns about how regulation is conducted to provide greater incentives for network investment and improvements in service standards; and
- providing greater incentives for embedded generation.

[16] Parer Report, p. 9

The Productivity Commission's review of the National Access Regime

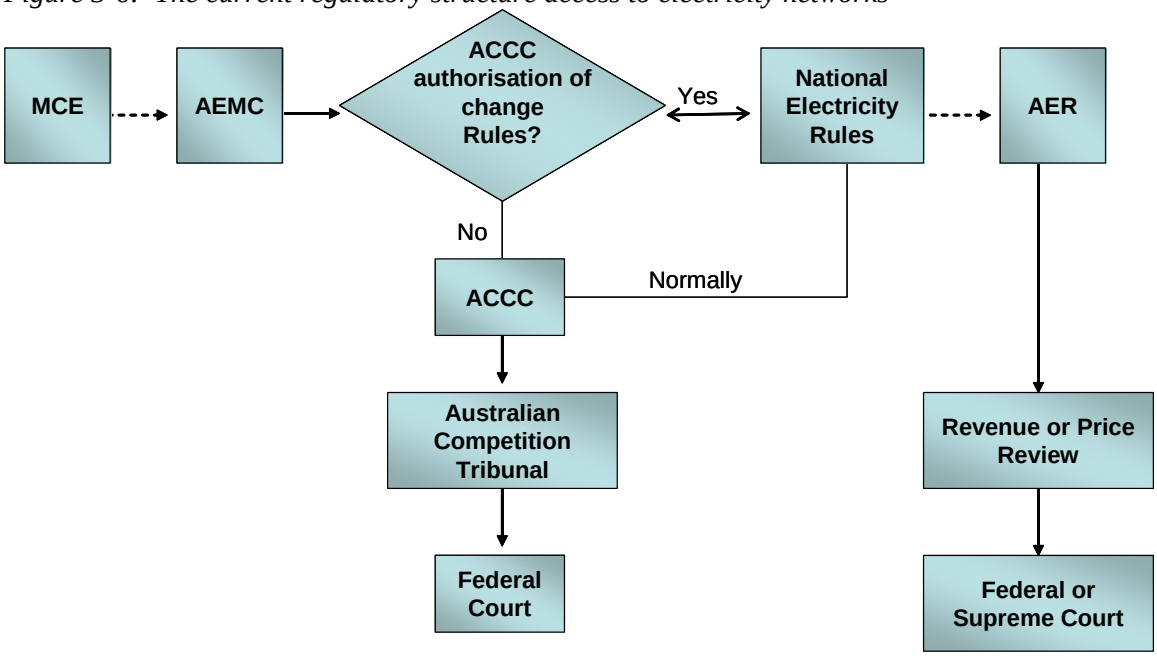
At about the time public debate was focusing on the issues that led to the COAG Review and the Parer Report, concerns that complexity in the national access regime could deter investment in essential infrastructure also led to the Productivity Commission conducting a review of the national access regime.[17]

The inquiry recommended changes to the national access regime, which included clarifying the regime's objectives and scope, strengthening incentives for commercial negotiations and improving the certainty and transparency of regulatory processes[18]. Consequently, Part IIIA of the *Trade Practices Act* was amended to provide for this.

The current regulatory arrangements

As a consequence of the COAG and Productivity Commission reviews outlined above, the institutional framework for the access regulation of electricity networks and other energy infrastructure has changed. We illustrate the new structure and the roles of its key components below.

Figure 3-6: The current regulatory structure access to electricity networks



Under the new arrangements, the *Ministerial Council on Energy (MCE)* is responsible for:

- national energy policy framework;
- policy oversight of and future strategic directions for the Australian energy market;

[17] Productivity Commission, Review of the National Access Regime, Report No 17, 2001.
[18] http://www.treasurer.gov.au/tsr/content/publications/NationalAccessRegime.asp

- developing legislation and the regulatory framework; and
- addressing longer term, systemic and structural energy issues that affect the public interest[19].

The Australian Energy Market Commission (AEMC) is responsible for:

- rule making and market development for networks and retail markets (except for retail pricing);
- undertaking electricity (and gas) market reviews and inquiries; and
- providing analysis and recommendations to inform MCE policy development

but must comply with statements of policy principle issued by MCE.

The National Electricity Code was also superseded by the National Electricity Rules ("the Rules") and NECA, the National Electricity Code Administration, was dissolved.

AEMC is now responsible for managing Rule changes which it must submit to the ACCC for authorisation under the *Trade Practices Act*. Figure 3-6 illustrates that one might normally expect some degree of discussion between AEMC and the ACCC on Rule changes rather than changes being 'passed on the nod'.

There are also rights of appeal on ACCC decisions on Rule changes, to the Australian Competition Tribunal (a judicial body) and ultimately the Federal Court.

The Australian Energy Regulator (AER) is responsible for enforcement and economic regulation of networks and retail markets throughout the NEM, in accordance with the National Electricity Rules. The AER is responsible for transmission network regulation at the time of writing, with the transfer of responsibility for distribution regulation within the NEM due to commence in July 2007.

Technically each jurisdiction still maintains its own access regime, but all have enacted legislation to confer regulatory powers over their access regimes on the AER and the AMEC.

Parties to revenue or price reviews undertaken by the AER have a right of appeal, to the Federal or Supreme Courts.

However, the AER will not assume all regulatory responsibilities. Some, principally technical and safety regulatory, responsibilities will remain with the jurisdictions. The Commonwealth

[19] The MCE's Energy Market Reform Working Group (EMRWG) recently commissioned an independent review of the impact of the draft National Electricity Rules regarding any structural or regulatory impediments that may impede Distribution Business's incentives to support development or uptake of economically efficient Demand Side Response and Distributed Generation. EMRWG is yet to consider the review's recommendations and no policy positions have been reached as at April 2007 (at the time of the review's publication). http://www.mce.gov.au/index.cfm?event=object.showContent&objectID=D89836FF-C8BF-F6CE-95B6CDA0F65F3C73

and jurisdictions are signatories to the Australian Energy Markets Agreement, which last amended in June 2006, sets out the agreed allocation of regulatory responsibilities as follows.

Table 3-3: Allocation of regulatory responsibilities

Economic regulation – AEMC and AER
• Distribution economic regulation • Service performance incentive schemes for network and customer service standards • Information requirements for the AER to undertake its regulatory functions • New connection and capital contribution charges • Distribution network expansion determining when extensions are part of a regulated service and how charges are levied • Distributor connection service obligations - connections and related services and the contractual relationship with retailer and customer • Distributor small customer disconnection/reconnection - allowable disconnections or reconnections • Distributor interface with other market participants • Metering obligations to install, maintain and read meters • Retailer obligation to supply to small customers at a default tariff with minimum terms and conditions • Retailer failure arrangements to ensure supply continuity and wholesale market financial integrity • Retailer small customer market contracts - minimum contract terms and conditions and marketing conduct • Distributor and retailer general business authorisations for matters other than technical capability and safety
Technical regulation – Jurisdiction and territory regulators
• Distributor technical/safety business licensing which require demonstration of technical capability • Small customer dispute resolution obligations for distributors and retailers to have schemes and participate in Ombudsman schemes • Load shedding and curtailment - customer supply reduction to maintain system security • Service reliability standard to ensure network security and reliability • Metering policies on the types of meters for specific customer classes, accredited service provider arrangements, and load profiling • Distribution and retail service areas - specification of geographical areas in which responsibilities apply

A consequence is that there is now a more streamlined institutional structure for regulation throughout the NEM. This is illustrated by comparing Table 3-4 below with Table 3-1.

Table 3-4: Current regulatory structures

	NEM							
	ACT	**NSW**	**SA**	**TAS**	**QLD**	**VIC**	**NT**	**WA**
Transmission, Distribution and Retail Obligations to Supply								
Govt. Policy	← MCE →						Territory	State
Regulation	← AER →						NTUC	ERA
FRC introduced	Yes	Yes	Yes	Review by 2010	2007	Yes	No	Review by 2009

See Appendix A for an explanation of the acronyms used in this table.

4 Network pricing equalisation arrangements

4.1 Introduction

This section outlines the principal network pricing equalisation or subsidy schemes currently in place, together with some further broader subsidy schemes.

Appendix D summarises the cost based, 'building block' approach generally taken by regulators to setting prices for regulated networks. The consequences of the principles outlined in Appendix D include network prices for customers that are strongly influenced by:

- density of distribution networks. A highly urbanised population centre may have lower cost per customer since total cost of supply is shared by a larger customer base with, for example, more customers per km of network; and

- proximity to generation (townships located further from generation sources require longer transmission lines to be built, thereby driving up costs).

4.2 Intra-network cross subsidies

4.2.1 Postage stamp pricing

The costs of distribution networks and part of the costs of transmission networks are spread across all customers who use the network, regardless of location. This principle is referred to as "postage stamp pricing".

All other factors being equal, a regional customer at the end of an extended distribution line may pay the same network tariff as a customer in a metropolitan area that may also live within that distribution area.

The costs that are spread among customers include costs of connection of the distribution network to the transmission network. For distribution networks sited further away from the principal sources of generation, these costs may be higher than for distribution networks with transmission connections closer to these points.

In addition to providing some equity of customer pricing within networks, postage stamp pricing balances objectives for networks to be of sufficient size to be financially viable with objectives of cost reflectivity.

It follows that:

- distribution areas that cover both metropolitan and regional areas are more likely to include these cross subsidies, than less diverse or less extensive networks; and

- the opportunities for changing these cross subsidies to the benefit of regional customers but to the detriment of metropolitan customers are limited as they would require a re-mapping

of the boundaries of regional distribution networks to encompass more metropolitan areas. This would appear impractical for privatised networks but might be an in-principle opportunity for government owned networks in Queensland and NSW for example. However, this would require a reversal of former reform decisions which brought about the current distribution network areas in those states.

South Australia, the ACT and Tasmania all have single distribution networks, thus maximising the opportunity for postage stamp pricing. However, in all of these cases, the networks and markets are less likely to be large enough to make a number of smaller networks viable.

4.2.2 Network loss factors

Section 3.2 describes the operation of network loss factors. While the effects of loss factors are reflected in energy rather than network charges, they nonetheless represent a form of network cross subsidy between customers closer to distribution/transmission network connection points and those further afield.

4.3 Inter-network cross subsidies

4.3.1 Victoria's Vesting Asset Adjustment

When assets were vested in the regulatory base of different distributors in 1994 (refer Appendix D.1.1), adjustments were made by government to ensure that the high costs of supplying services to rural areas were partly subsidised by urban energy users to limit the short to medium term price differentials that could result between customers resident in different network areas.

A regulatory asset value represents the present value of future income streams from that asset. Therefore, by making these adjustments and establishing them in the regulatory framework prior to the sale of the network businesses, the government:

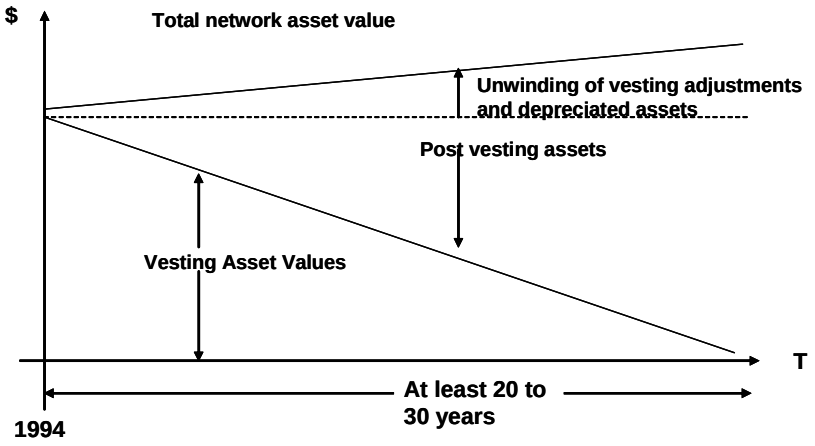
- reduced the value and potential sale proceeds of Eastern Energy and Powercor; and
- enhanced the value and potential sale proceeds of the other distributors, although Table 4-1 indicates that over the whole Victorian network there was a write down in value of $53m.

Table 4-1: Cross-subsidy in vesting asset arrangements in 1994[20]

Original asset values	Eastern (now SPAusNet)	Powercor	Solaris (now Alinta)	CitiPower	United	Total
DORC ($m)	1,045	1,227	361	482	743	3,859
Adjustment ($m)	(218)	(161)	61	129	136	(53)
Adjusted book value	828	1,066	422	611	879	3,806

As time progresses, the value of the vested assets and the corresponding adjustments will diminish, and they will be replaced with new purchased assets not subject to such an adjustment. Accordingly, the value of the cross-subsidies will unwind with time as shown in Figure 4-1.

Figure 4-1: Unwinding of vesting asset adjustments



It is not readily possible to determine the current value of these cross subsidies because their calculation would require knowledge of the current written down value of the vesting assets in SP AusNet and Powercor. This information is not publicly available. However, we attempt the following broad brush indicative analysis, based on an assumption that the vesting assets had on average a remaining life of 25 years in 1994 (25 years is an illustrative assumption).

[20] Victorian Electricity Tariff Order, Clause 5.10b, June 1995

	SP AusNet	Powercor
Present value of original subsidy in 1994	$218m	$161m
Assume now depreciated by approximately 50%		
2007 present value of remaining subsidy	$110m	$ 81m
Assume a real discount rate of[21]	6.4%	6.3%
Equivalent real annuity over say 12 years	$12.6m p.a.	$9.2m p.a.
Assumed network load for 2006 GWh	7,374	10,024
Equivalent value of subsidy	0.2 c/Kwh	0.1 c/Kwh

This is a highly illustrative and approximate calculation based on the assumptions set out above. With these caveats, it indicates that, if the vesting assets were to become fully depreciated by say 2019, Powercor customers might then observe an average increase in network prices over current levels in real terms of about 0.1c per kWh and SP AusNet customers of about 0.2c per kWh.

4.3.2 Victoria's Transmission Equalisation Adjustment (TEA)

Our understanding is that the TEA was introduced at the time of Victoria's industry reform and privatisation as a pragmatic means of supplementing the vesting asset adjustments described above to constrain the price differentials between regional and metropolitan areas that would otherwise result. The intention, including its planned phasing out, was not to permanently insulate customers in Victoria from cost reflective pricing but to graduate the transition from the former pricing regime to the new one. The TEA is not consistent with the pricing rules of the National Electricity Rules, but is permitted as a formal Derogation to the Rules. It is also important to note that the TEA preceded the National Electricity Code and hence its legacy status provided a reason for the derogation. Section 6 considers the feasibility of a scheme that may prolong or extend the TEA or a similar arrangement.

We note that the MCE has recently announced that it has asked its Standing Committee of Officials (SCO) to develop a work program to implement a range of initiatives including a review of all remaining derogations from the National Electricity Rules[22]. This would include the TEA but until the terms of reference of the work program are known it would be premature to speculate on the impact this may have on the TEA and its continuation.

The TEA scheme adjusts the fees for the use of the transmission system for distribution providers who service high cost areas. The subsidy is designed to fall by 33 percent of current levels in years 2010, 2015 and 2020.

[21] Essential Services Commission: Electricity Distribution Price Review 2006-10. Final Decision Volume 2, October 2006
[22] Ministerial Council on Energy, Communiqué – Melbourne 25 May 2007

The scheme adjusts the fees for the use of the transmission system for distribution providers who service high cost areas (i.e. SP AusNet and Powercor). Distribution companies in the metropolitan areas (i.e. Alinta, CitiPower and United Energy) must provide a payment to subsidise the high cost of distributing electricity in other areas. The amount of equalisation adjustments are shown below[23].

Table 4-2: Equalisation adjustments

Distribution business	Equalisation adjustment ($'000)
SP AusNet	(4,939)
Powercor	(19,011)
Alinta (formerly AGL)	5,171
CitiPower	5,920
United Energy	12,859

The actual level of allowance provided each year is determined by multiplying the above adjustments with the relevant factor shown in the following table. The amount of the cross subsidy reduces with time and phases out after year 2020.

Table 4-3: Equalisation adjustment factors

Year	Relevant factor
Jan 2001 – June 2001	40%
July 2001 – June 2005	80%
July 2005 – June 2010	60%
July 2010 – June 2015	40%
July 2015 – June 2020	20%
Thereafter	nil

Section 5.1 illustrates the effect of the TEA on Victorian customers.

4.3.3 Network Tariff Rebate in Victoria

The Network Tariff Rebate aims to close the gap in electricity prices between city and country Victoria. The rebate intends to compensate households and small businesses which are "disadvantaged by retail tariff adjustments or the higher network costs of supplying electricity to their geographic areas." [24]

To qualify for the scheme, customers must be:

- covered by the Victorian government's statutory safety net framework; and
- located in Powercor or SP AusNet electricity network areas.

[23] Office of the Regulator-General Victoria, Electricity Industry Regulatory Statement, Issue No 2, 1/9/95, Attachment 7, Clause 4.3.1

[24] http://www.doi.vic.gov.au/doi/internet/energy.nsf/AllDocs/B824FE15CF89E0ADCA256CF30004E67B?OpenDocument

The safety net framework is structured to protect customers who are unable to participate effectively in the competitive energy market upon the introduction of full retail competition. For example the government targeted certain rural and low income customers.

The NTR was preceded by the Special Power Payment. This and government constraints on retail prices arose from a Victorian government commitment in 2000 that no customers would be worse off as a result of the introduction of FRC. In particular, certain categories of rural customers, such as "hot water" domestic customers, would have been subject to significant price increases as retail cross subsidies unwind with the introduction of FRC.

The amount of the NTR depends on customer category, location, and the split of usage between peak and off-peak periods. Eligible customers are entitled to the rebate up to *average usage levels*[25]. This concept intends to provide target customers (i.e. households and small businesses) with assistance. On the other hand, larger electricity users such as commercial enterprises are not entitled to a rebate beyond the *average usage level.* This effectively exposes them to more cost reflective pricing which the government describes as "providing an incentive to consider other more economical solutions such as alternative fuel or adopting more energy efficient practices".

The following table shows how a small business may be subject to different rebates depending on its location, and therefore distributor.

Table 4-4: Victoria's Network Tariff Rebate Scheme

Type of tariff	**Peak usage limit (kWh)**	**Powercor**	**SP AusNet**
		Rebate (c/kWh)	**Rebate (c/kWh)**
N,E,G	4,000	0.3	0.4
DH/DL	8,000	0.6	0.8
E1,N1,B1	8,000	0.1	1.3

Type of tariff	**Off-peak usage limit (kWh)**	**Powercor**	**SP AusNet**
		Rebate (c/kWh)	**Rebate (c/kWh)**
N,E,G	4,000	n/a	n/a
DH/DL	8,000	0.2	1.3
E1,N1,B1	8,000	0.1	0.5

Source: Department of Infrastructure, Victoria

While the size of the rebate used to be determined on an annual basis, the government has attempted to provide more certainty to customers by setting the limits and rebates over a longer regulatory period. The current limits were established in 2005 and will be phased out on 31 March 2008. Over that period, the government has committed $110m of funding to the scheme.

[25] To be eligible, customers must consume less than 160,000 kWh of electricity p.a. For the majority of customers the *average usage level* is 4,000 kWh p.a., plus an additional 4,000 kWh p.a. if there is off-peak electricity usage for hot water of space heating.

4.3.4 New South Wales asset values

The values of the regulatory asset base for distributors in NSW were originally established in 1998. The Government policy at the time was to restrain asset values for rural distributors. As the value of the asset base determines the revenue the distributors are allowed to earn, limiting this prevents increases in the price of electricity.

Consequently, IPART established a regulatory asset value for the Australian Inland Energy (now part of Country Energy) at a lower value than what might have been obtained through the DORC method.

In the 2004 regulatory price review, Country Energy attempted to increase its asset value by reverting back to the DORC method, but this argument was rejected by IPART on the basis that these are 'sunk' assets and should not be allowed to generate a return.[26]

This mechanism has analogies with Victoria's vesting asset value adjustments and, like Victoria's arrangements, will gradually unwind.

NSW also has in place an Electricity Tariff Equalisation Fund intended to assist government owned retailers to meet NSW's regulated retail tariff commitments. This arrangement is arrived at the retail, rather than the network, level and we do not describe it further, other than to provide a reference to it at http://www.treasury.nsw.gov.au/etencorp.htm, and to comment that the Parer Report recommended that this arrangement be terminated on the basis that it raises barriers to competition in the wholesale energy market.

4.3.5 Queensland CSOs

Equity objectives are facilitated in Queensland through the provision of Community Service Obligations (CSO) funding to electricity distributors. The amount of CSO funding in Queensland is significant. This is principally due to the exceptional length and sparse customer density of Ergon Energy's network.

Both the main electricity distributors, Energex and Ergon Energy, have very similar asset values at approximately $3.9 billion and revenue requirements. However, Table 4-5 shows that the customer and load profile for the distributors vary considerably.

Table 4-5: Comparison of distribution customers and loads in Queensland

Distributor	Energex	Ergon Energy
Required revenue 2005-06[27]	$562 m	$526 m
Forecast energy (approx)[28]	19,770 GWh	13,120 GWh
Average price (c/kWh)	2.84	4.01
Length of distribution lines[27]	45,400	138,330
Customers per km of line[27]	25.5	4.2
Network service area (sq. km)	25,300	1,698,100

[26] IPART, NSW Electricity Distribution Pricing 2004/06-2008/09 Final Report, page 49
[27] QCA 2005 Electricity Distribution Price Review
[28] KPMG estimate for 2005-06 based on data in QCA 2005 Price Review

Figure 4-2: Queensland CSOs

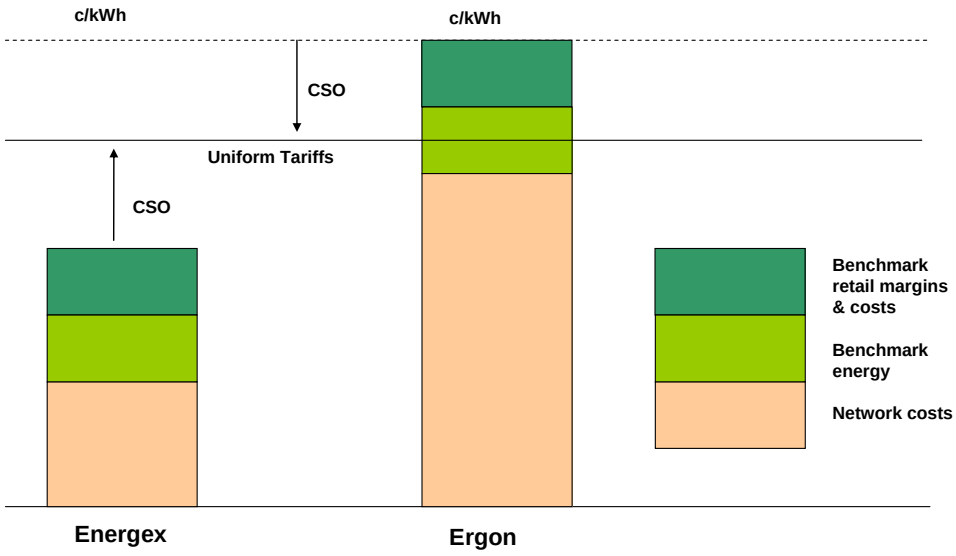


Figure 7 illustrates how the network costs for Energex, who largely has metropolitan customers, are lower than that of Ergon's, who predominantly operates in rural areas. The difference in the cost of electricity supply between these two distributors leads to the need for a CSO. The CSO is largely funded by Energex customers. However, we understand that the Queensland government bears the risk or benefit of any mismatch between the CSO funding provided by Energex's customers and CSO payments due to Ergon.

We are not aware of publicly available information on the amount of the CSOs.

However, the data set out in Table 4-6 would indicate that, based on an assumption that both Energex and Ergon have identical benchmark energy costs and margins, Energex's customers would need to subsidise Ergon's customers by approximately $92m in 2005-06 to achieve equivalent average network tariffs.

Table 4-6: Illustration of Queensland CSO cross subsidies 2005-06

	Energex	**Ergon Energy**
Required revenue	$562m	$526m
Cross subsidy payment/(receipt)	$92m	$(92m)
Revised revenue	$654m	$434m
Forecast energy	19,770 GWh	13,120 GWh
Average price after CSO	3.31 c/kWh	3.31 c/kWh
Cross subsidy payment/(receipt)	0.47 c/kWh	0.70 c/kWh

This brief analysis indicates that the Queensland cross subsidies may be significantly higher than those of Victoria.

CSOs are administered by the Queensland Government at the retail level. That is, retailers are compensated for their provision of services to 'franchise[29]' customers. The derivation of the retail benchmark costs used to determine the appropriate level of CSO can be judgmental and contentious. Using a retail mechanism to effect the CSO may be rendered impractical by the implementation of full retail contestability in 2007 and the sale of Sun Retail (formerly called Energex Retail) and part of Ergon Retail. The associated Benchmark Pricing Arrangement, which protects the government owned retailers from market pricing risk of energy costs differing from the assumed benchmarks has also been criticised for stifling competition in the wholesale energy market.[30] How the Queensland government deals with the network price differentials in future is likely to provide a precedent for the construction of inter-network cross subsidies. One route that may be open to the Queensland Government as the owner of both Ergon and Energex networks might be to amalgamate the two networks to provide 'postage stamp' distribution pricing across all of Queensland.

4.3.6 MCE review of CSOs

We note that the MCE has recently announced that it has asked the SCO to develop a work program to implement a range of initiatives including a national review of energy CSOs with a view to developing a consistent national framework[31].

The Queensland CSO and the Victorian Network Tariff Rebate are examples that could fall within the scope of such a review. However until the terms of reference of that work program are better known it would be premature to speculate on its implications for the CSO's outlined above.

4.4 Summary and conclusions

Table 4-7: Inter network cross subsidies

State		Illustrative dollar amount[32] in 2007 (applicable to all network customers)	Timing
NSW	Asset revaluation for part of Country Energy	Unknown	Will unwind as assets become fully depreciated
Vic	Vesting asset adjustment	Estimated figure possibly in the order of $12.6m per annum for SP AusNet Estimated figure possibly in the order of $9.2m per annum	Will unwind as assets become fully depreciated

[29] Non-contestable customers who pay uniform regulated tariffs regardless of location.
[30] Eg refer to the CoAG Review of Energy Markets
[31] Ministerial Council on Energy, Communiqué – Melbourne 25 May 2007
[32] These figures are illustrative only and subject to the caveats explained in Section 4.3.1.

		for Powercor	
Vic	TEA	$3.3m – SP AusNet $12.6m – Powercor	Will be phased out by June 2020
Qld	CSO	Estimated figure possibly in the order of $92m per annum. Benefits regional customers in Ergon's area only	Retail CSO likely to be superseded but future is uncertain

In addition, all Tasmania and South Australia regional business customers receive intra-network cross subsidies, because a single distribution network exists in each state. There is no indication at present that these cross-subsidies would unwind.

The above table shows that cross-subsidies to provide greater pricing equity are generally implemented at the time of reform and/or when government is a utility shareholder. However, none of these inter-network cross-subsidies in the NEM can be regarded as permanent, with the possible exception of Queensland. They can currently be expected to be replaced by more cost reflective mechanisms.

5 The evidence - What's the problem in practice?

This section of the report presents the findings from the quantitative and qualitative analysis of information collected from a sample of 10 businesses across 27 locations in Victoria, New South Wales, Queensland and South Australia. The information was sought from participating businesses through two mechanisms:

- obtaining copies of a business' electricity bills for a number of different locations and calculating load-weighted average charges (in cents per kWh) to compare network charges across locations (*quantitative data*); and

- conducting an interview (either face to face or via teleconference) to obtain qualitative information relating to the business' energy dependence, usage and costs, other relevant information relating to location choice, long-term impact of changes in electricity charges and size of operations (*qualitative data*).

To protect participants' confidentiality, this report:

- does not disclose the names of participating businesses; and

- presents data and findings at an aggregated level.

Appendix E sets out in detail the electricity network cost and usage data obtained from the sample, along with a description of the approach taken including commentary on the rationale for sample selection.

Appendix F sets out the purpose of the interviews conducted with businesses, the list of questions covered in the interviews, and the findings of the qualitative analysis.

5.1 Quantitative analysis - key findings

5.1.1 Comparison of average network charges by location

Using the billing information obtained from businesses in the sample, load-weighted average network charges in cents per kWh (exclusive of GST) were calculated for each location to compare network charges across locations. Load-weighted averages have been calculated (as opposed to time-weighted averages) to allow for the differences in electricity consumption that can occur month-to-month due to a business' load profile varying throughout the year.

Table 5-1 outlines for each State:

- average network charges for regional and metropolitan businesses in the sample on a cents per kWh basis; and

- the differences between the regional average network charge and metropolitan average network charge expressed on a cents per kWh basis and as a percentage of the metropolitan average network charge.

By "Metropolitan" we mean within the bounds of the capital city in each State. By "Regional" we mean all other locations.

Table 5-1: Average network charges – by State and Region

Regional / Metro	Average Network Charge (c/kWh)			
	Vic	NSW	Qld	SA
Regional	3.26	4.16	2.67	5.18
Metro	2.92	3.78	1.87	-
Difference (c/kWh)	*0.34*	*0.38*	*0.79*	-
Difference (%)	*12%*	*10%*	*42%*	-

Table 5-1 highlights that average network charges for businesses in the sample are typically more expensive in regional locations than in metropolitan locations.

However, care has to be taken in interpreting or referring to these averages. The sample size is limited and, in addition to whether a business is located in a regional or metropolitan area, a business' average network charge is also influenced by the assets of the network the business is connected to, the network tariff structure, its load and consumption profile (primarily load factor).

There is a risk that the average differences illustrated above could reflect the impact of these other factors on the limited sample sizes rather than purely regional and metropolitan differences. Also the sample is not of sufficient size to allow a meaningful statistical correlation analysis. Therefore we disclose in Table 5-2 and Figure 5-1 below the ranges of differences between metropolitan and regional areas.

There is significant variation around the average network charges calculated for a particular regional or metropolitan area. To highlight this variation, the range in average network charges calculated for businesses in particular regional and metropolitan areas is presented in the following graph to allow comparison across States.

Table 5-2: Range in average network charges – by State and Region

State	Average network charge (c/kWh)				Difference between Metro and Regional			
	Metro		Regional					
	Low	High	Low	High	Low - Low	Low - High	High - Low	High - High
Vic	2.29	4.95	1.89	6.56	-17%	186%	-62%	33%
NSW	3.78	3.78	3.78	4.38	0%	16%	0%	16%
Qld	1.84	2.22	2.25	2.80	22%	52%	1%	26%
SA	5.18	5.18	-	-	-	-	-	-

Figure 5-1: Range in average network charges for businesses in the sample – by State and Region

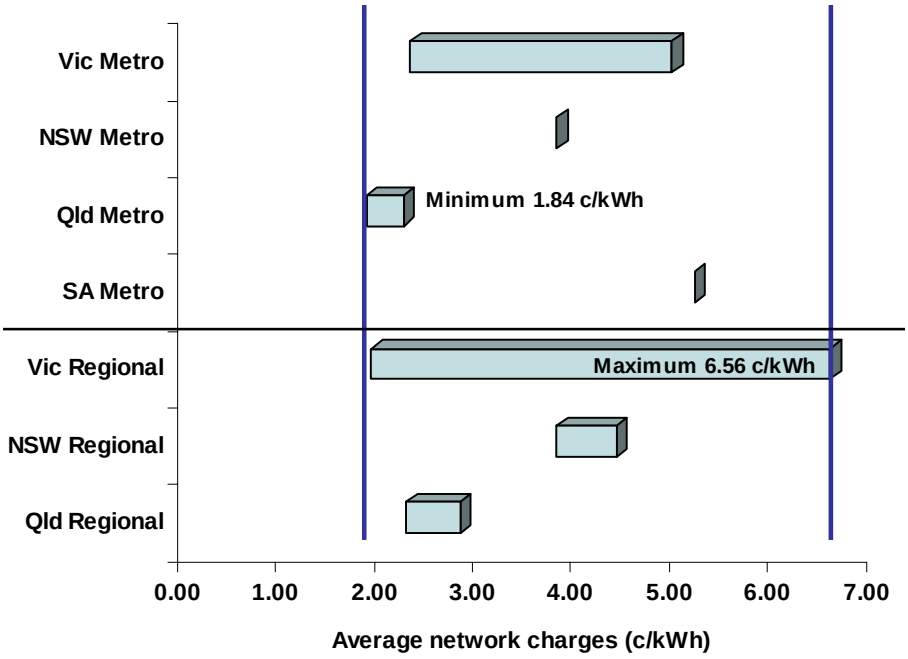


Table 5-2 and Figure 5-1 illustrate that:

- for NSW and Queensland, the lowest regional charge was no less than or greater than the highest metropolitan charge;
- Victoria has the greatest range of metropolitan and regional prices. This may reflect the greater sample size available from that State;
- unlike the other States the Victorian sample disclosed the greatest overlap between regional and metropolitan prices. For example, only one location in the Victorian regional sample had an average price that was greater than the highest Victorian metropolitan price of 4.95 cents per kWh in the sample;
- the lowest price in the Victorian sample arose at a "regional location". However, this may not be typical of regional locations generally. We explain why below in the further commentary on each state; and
- there is only one business from South Australia in the sample. However, South Australia has only one distribution network, and therefore "postage stamp" distribution network pricing might be expected to apply regardless of metropolitan or regional location. Accordingly, the South Australian metropolitan location has a relatively high "metropolitan" network price.

Table 5-3: Victorian Regional and Metropolitan Prices

Regional (c/kWh)	Metro (c/kWh)
6.56	4.95
4.66	
4.59	
4.19	
3.90	3.83
3.52	
3.40	3.19
3.04	3.18
2.59	2.77
	2.53
	2.29
1.89	

Table 5-3 demonstrates that, even if the lowest regional price were removed from the sample, all but two metropolitan prices would be more expensive than at least one regional price. However, if the highest metropolitan price were removed the sample, 50 percent of the regional sample were more expensive than any of the metropolitan sample.

Also the metropolitan sample was predominantly comprised of businesses in the Alinta, Citipower and United Energy networks. Therefore, it is less likely that the relatively high metropolitan prices are the result of intra-network cross subsidies with regional customers.

Figure 5-2: Range in Victorian average network charges – by Region

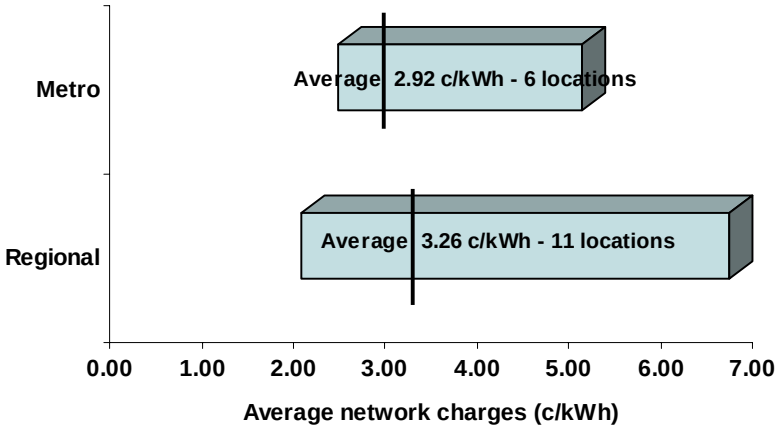


Figure 5-2 highlights that a regional business in the sample, rather than a metropolitan business, has the lowest average network charge for Victorian businesses in the sample (17 percent less than the lowest metropolitan average network charge).

This arises due to one particular location in the sample which:

- has a stable load profile and a high load factor. This means that it is a cost efficient customer for the network; and

- is sited in a satellite town of Melbourne and is connected to a distribution network that serves predominantly metropolitan customers. Therefore although this customer is defined as a regional customer for the purpose of this analysis, *from a network pricing standpoint it is regarded as if it were an efficient, relatively low cost metropolitan customer*.

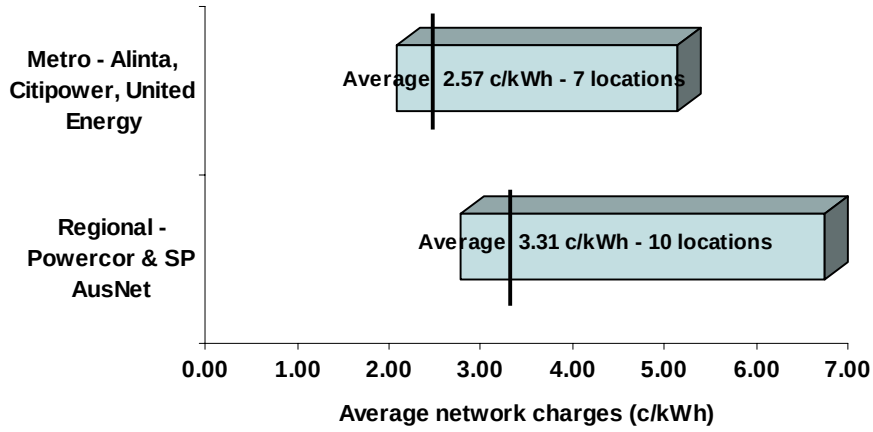
One might reasonably conclude from this that this customer 'skews' the results. We have therefore also provided the Victorian sample analysed by distribution area where we have assumed:

- all of Powercor and SP AusNet customers to be in a "regional distribution area"; and

- all other network customers to be in a "metropolitan distribution area".

This is similar to the basis on which the Network Tariff Rebate (described in Section 4) is attributed to different customer groups.

Figure 5-3: Range in Victorian average network charges by Distribution area



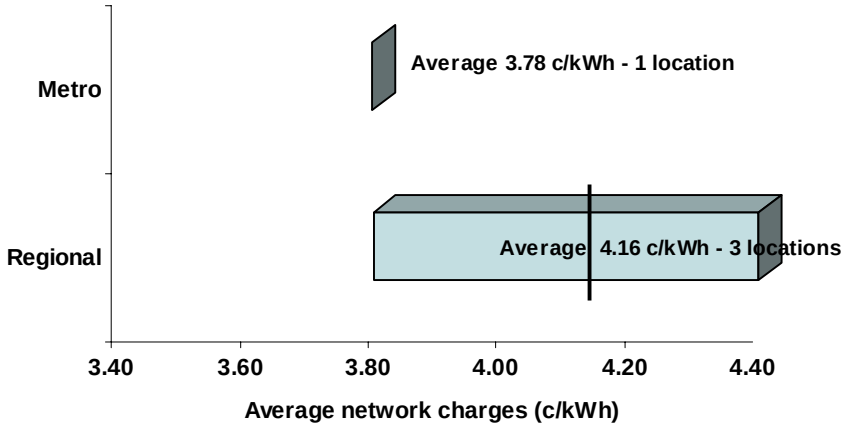
This illustrates that the overlap in prices in Victoria outlined in Table 5-3 is not highly sensitive to the definitions of "regional" and "metropolitan" business used by this study.

However, while the lowest priced Victorian customer in the sample is not representative of regional customers generally, adopting the analysis set out in Figure 5-3 to delineate regional from metropolitan customers might deal with this customer but, at the same time, would classify many metropolitan customers of Powercor for example as 'regional', who also would not be representative of regional customers.

The example of the lowest regional price therefore serves to illustrate that the existence of intra-network cross subsidies means that, for network pricing purposes, the boundary between 'regional' and 'metropolitan' customers is not sufficiently clear cut to allow each to be thought of as mutually exclusive groups. Some regional customers will be priced as metropolitan customers and vice versa. However, while this may blur the boundary as Figures 5-1 to 5-6 illustrate, regional customers generally pay higher network charges than metropolitan customers.

If this particular business was not in the sample then the range in regional average network charges would shift to the right (i.e. the lowest average network charge for Victorian regional businesses in the sample would be higher than the lowest average network charge for Victorian metropolitan businesses in the sample). Victorian regional average network charges for businesses in the sample would range between 2.59 and 6.56 cents per kWh, with an average of 3.37 cents per kWh.

Figure 5-4: Range in NSW average network charges – by Region



In comparison to Victorian businesses in the sample, the range of average network charges for NSW regional businesses in the sample shows significantly less variation (from 3.78 to 4.38 cents per kWh). Note there is only one metropolitan NSW business in the sample.

This business had the same average network price as the lowest priced NSW regional business in the sample. This appears to be coincidental, rather than due to the two locations being in the same distribution area.

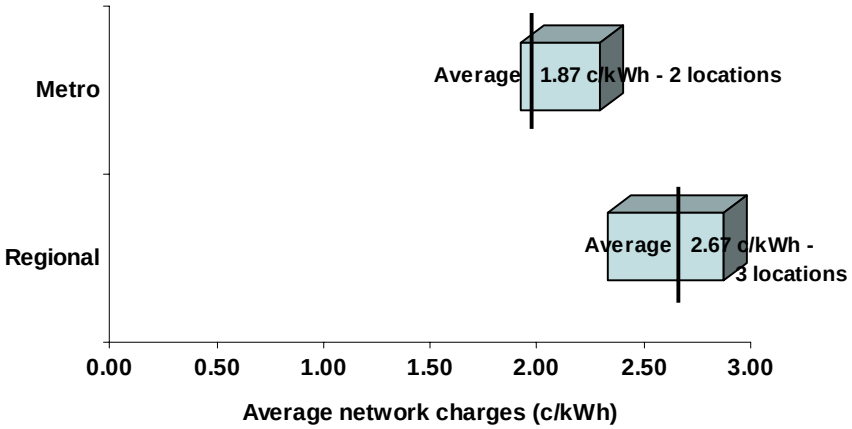
We have also analysed the NSW sample by distribution area where we have assumed:

- all of County Energy and Energy Australia customers to be in a "regional distribution area"; and

- all Integral Energy customers to be in a "metropolitan distribution area".

This does not change the classification of NSW businesses in the sample and therefore does not impact on the average network charges calculated for NSW regional or metropolitan businesses in the sample.

Figure 5-5: Range in Queensland average network charges – by Region



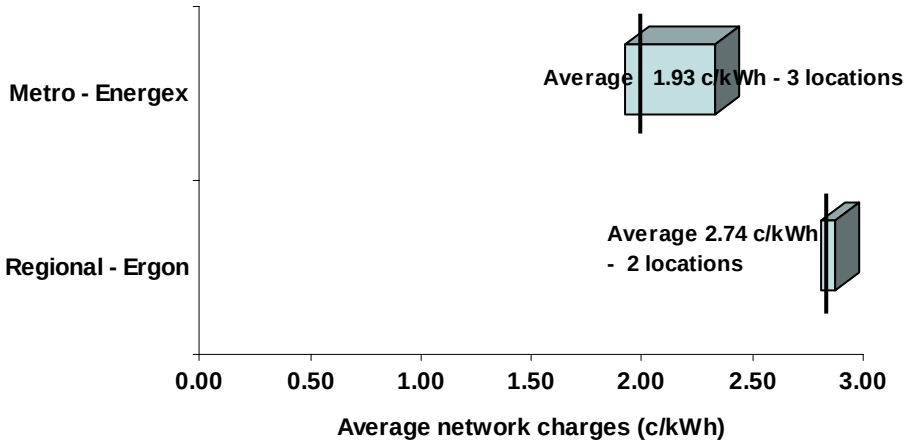
In comparison to Victorian businesses in the sample, the average network charges for Queensland businesses in the sample do not vary that greatly within each region (by 0.37 and 0.55 cents per kWh for metropolitan and regional businesses respectively).

The difference in charges between metropolitan and regional locations for Queensland businesses in the sample were in the range of 1 to 52 percent. The 1 percent difference between the lowest regional and highest metropolitan average network charges appears to be due to the regional business being located in Energex's distribution area which serves Queensland's metropolitan customers. It is therefore likely to benefit from the intra-area cross subsidy through sharing a common distribution network with Brisbane.

Again, we have also analysed the Queensland sample by distribution area where we have assumed:

- all of Ergon Energy's customers to be in a "regional distribution area"; and
- all Energex customers to be in a "metropolitan distribution area".

Figure 5-6: Range in Queensland average network charges – by Distribution area



Analysis by distribution area changes the classification of one regional Queensland business in the sample that is located in Energex's distribution area. However, the impact on the average network charges calculated for Queensland regional and metropolitan businesses in the sample is relatively small (increasing by 0.06 and 0.07 cents per kWh for metropolitan and regional businesses respectively).

Table 5-4 summarises the range in average network charges for businesses in the sample by Distribution area.

Table 5-4: Range in average network charges for businesses in the sample – by State and Distribution area

State	Average network charge (c/kWh)				Difference between Metro and Regional DBs			
	Metro DB		Regional DB					
	Low	High	Low	High	Low - Low	Low - High	High - Low	High - High
Vic	1.89	4.95	2.59	6.56	37%	247%	-48%	32%
NSW	3.78	3.78	3.78	4.38	0%	16%	0%	16%
Qld	1.84	2.25	2.73	2.80	48%	52%	21%	24%
SA	5.18	5.18	-	-	-	-	-	-

We comment that:

- for NSW and SA, there is no difference from the results outlined above in Table 5-2 and Figure 5-1;
- Victoria has the greatest range of average prices for both regional and metropolitan distribution areas and the greatest degree of overlap;

- some regional members of the Victorian sample had average prices less than metropolitan prices, although the "regional" business with the lowest price is located within a "metropolitan distribution area";

- both Queensland and NSW demonstrated more distinct differences between metropolitan distribution area and regional distribution area prices than Victoria, which became more pronounced for Queensland due to one "regional" business being located within a "metropolitan distribution area".

Locational differentials

Based on the data in the sample, the largest differentials in average network charges is between:

- one regional location to another were regional Queensland and regional NSW (56 percent);

- one metropolitan location and another were metropolitan Queensland and metropolitan South Australia (176 percent).

Table 5-2 and Figure 5-1 also show that metropolitan prices in Victoria and South Australia are potentially higher than regional prices elsewhere.

However, it would be unwise to conclude from this that metropolitan prices are *necessarily* higher. The section above for example, illustrates a significant degree of overlap in pricing between regional and metropolitan customers:

- of the existence of intra-network and inter-network cross subsidies in Victoria that may mitigate regional/metropolitan pricing differentials in Victoria;

- we understand that the Queensland businesses in the sample have negotiated non-standard network tariffs; and

- South Australia has a single distribution network, thereby removing the distinction between metropolitan and regional distribution pricing in that state.

Appendix E.4.1 provides more supporting data.

5.1.2 Other factors that cause variation in average network charges

Comparison of average network charges by industry sector

The differences in average network charges calculated for businesses in the sample are strongly influenced by a business' load profile and load factor. A comparison of the average network charges calculated for four Victorian businesses in the same distribution area with the same network tariff provided in Appendix E.4.2 shows that average network charges can vary despite sharing the same distribution area and network tariff.

Load profile and load factor are often related to the nature of the business and the demands it places on the network.

Table 5-5 outlines the average network charges for regional and metropolitan businesses in the sample by State and Industry sector as classified by the ASX[33].

Table 5-5: Average network charges – by State, Region and Industry

State	Regional / Metro	Average Network Charge (c/kWh)		
		Consumer Staples	Industrials	Materials
Vic	Total	2.72	3.86	3.56
	Regional	2.83	4.19	4.08
	Metro	2.54	3.19	3.25
	Difference (c/kWh)	*0.29*	*1.00*	*0.83*
	Difference (%)	*12%*	*31%*	*25%*
NSW	Total	4.11	-	4.24
	Regional	4.11	-	4.36
	Metro	-	-	3.78
	Difference (c/kWh)	-	-	*0.58*
	Difference (%)	-	-	*15%*
Qld	Total	2.28	-	-
	Regional	2.67	-	-
	Metro	1.87	-	-
	Difference (c/kWh)	*0.79*	-	-
	Difference (%)	*42%*	-	-
SA	Total	-	5.18	-
	Metro	-	5.18	-
	Difference (c/kWh)	-	-	-
	Difference (%)	-	-	-

As highlighted by Table 5-5, industry sector and load profile can impact on a business' average network charge. We note that industry sector does not impact on the differential between regional and metropolitan average network prices, and that the different averages for regional and metropolitan businesses is a function of variability within the sample.

For the Victorian businesses included in the sample, those businesses in the Consumer Staples have significantly lower average network charges in both regional and metropolitan locations than those businesses in the Industrials and Materials sectors. Low average network charges are also associated with businesses in the sample that have relatively flat consumption profiles and a high load factor, which results in more efficient use of the electricity network. In comparison, businesses in the sample that have variable consumption profiles and low load factors due to the production-cycle nature of their operations may have a less efficient use of the network.

The four Queensland businesses in the Consumer Staples sector have the lowest average network charges in the sample (for both regional and metropolitan businesses). These

[33] The ASX uses the joint Standard and Poor's/Morgan Stanley Capital International Global Industry Classification Standard (GICS) to classify listed entities. GICS consists of 10 Sectors aggregated from 24 Industry Groups, 67 Industries, and 147 Sub-Industries currently covering over 27,000 companies globally.

differences are likely to be a function of specific network tariffs negotiated by those businesses and the consumption profile for businesses in the sample.

Comparison of average network charges by level of consumption

Table 5-6 outlines the average network charges for regional and metropolitan businesses in the sample by State and level of consumption on a cents per kWh basis.

Table 5-6: Average network charges – by State, Region and level of consumption

State	Regional / Metro	Average Network Charge (c/kWh)			
		<1,000,000 kWh	1,000,000 - 5,000,000 kWh	5,000,000 - 10,000,000 kWh	>10,000,000 kWh
Vic	Regional	6.56	3.65	2.91	3.04
	Metro	4.95	3.00	-	2.84
	Difference (c/kWh)	*1.61*	*0.65*	-	*0.20*
	Difference (%)	*32%*	*22%*	-	*7%*
NSW	Regional	-	-	4.36	4.11
	Metro	-	3.78	-	-
	Difference (c/kWh)	-	-	-	-
	Difference (%)	-	-	-	-
Qld	Regional	-	2.55	-	2.73
	Metro	-	2.22	-	1.84
	Difference (c/kWh)	-	*0.33*	-	*0.88*
	Difference (%)	-	*15%*	-	*48%*
SA	Regional	-	-	-	-
	Metro	*5.18*	-	-	-
	Difference (c/kWh)	-	-	-	-
	Difference (%)	-	-	-	-

Data for locations outside of Victoria is limited, restricting comparison by annual consumption level to Victoria and, to a lesser extent, Queensland.

There is a general trend in the average network charges for Victorian businesses in the sample (both regional and metropolitan) to decrease as the annual consumption level increases. Further, the difference between regional and metropolitan average network charges for Victorian businesses in the sample (both regional and metropolitan) also decreases as the annual consumption level increases. This is likely to be a function of the network tariff structures for businesses in the sample, with the larger businesses able to spread their fixed charges over larger total consumption resulting in a lower average network charge than businesses with lower annual consumption levels.

Queensland businesses in the sample have the lowest average network charges in the sample, regardless of annual consumption level. However, Queensland businesses with annual consumption greater than 10,000,000 kWh have the most significant difference between regional and metropolitan average network charges (48 percent). Again, this is likely to be a function of the customer specific network tariffs in the sample, as discussed above.

5.1.3 Illustrative examples of dollar impact of differential between regional and metropolitan locations

The following tables provide illustrative examples of the dollar impact of the differential between regional and metropolitan locations for two businesses in the sample and how this can vary across the NEM States.

The base case in each example is a regional Victorian business in the sample. Appendix E.5 outlines the assumptions used in the calculations of annual network charges including the particular tariffs included in analysis. It is important to note that these are illustrative examples only and that significant variation in the results can occur depending on the assumptions included in the analysis.

Example 1 – Low Voltage customer

A small manufacturing business is located in regional Victoria with annual electricity consumption around 1,400,000 kWh (or 1.4GWh). Estimated annual network charges have been calculated using a sample business' actual monthly peak consumption, off peak consumption and maximum demand data from November 2005 to October 2006, and applying a comparable tariff for the particular business type in other locations in the sample.

Table 5-7: Estimated impact of differential between regional and metropolitan locations on annual network charges – Example 1 Low voltage customer

Regional / Metro	Annual Network Charge ($)			
	Vic	NSW	Qld	SA
Regional	63,000	73,000	73,000	62,000
Metro	53,000	57,000	51,000	62,000
Difference ($)	***10,000***	***16,000***	***22,000***	**-**
Difference (%)	***19%***	***28%***	***43%***	**-**

Applying a comparable interstate tariff to the sample business' data highlights that regional network charges in this example are higher than metropolitan network charges in each State (apart from South Australia which has postage stamp pricing), although the scale of this difference can vary significantly from $10,000 per annum in Victoria (or 19%) to $22,000 in Queensland (or 43%).

Example 2 – High Voltage customer

A larger manufacturing business is located in regional Victoria with annual electricity consumption around 9,000,000 kWh (or 9GWh). The process for calculating annual network charges used as in Example 1 has been applied here.

Table 5-8: Estimated impact of differential between regional and metropolitan locations on annual network charges – Example 2 High voltage customer

Regional / Metro	Annual Network Charge ($)			
	Vic	NSW	Qld	SA
Regional	226,000	296,000	246,000	247,000
Metro	172,000	196,000	191,000	247,000
Difference ($)	***54,000***	***100,000***	***55,000***	***-***
Difference (%)	***31%***	***51%***	***29%***	***0%***

The increase of this larger business' annual network charges from being located in regional Victorian compared to metropolitan Melbourne, is estimated to be around $100,000 per annum or 51%.

In this example, regional network charges are higher than metropolitan network charges within the same State (apart from South Australia as discussed above), and again the scale of this difference can vary significantly.

5.1.4 Impact of the Victorian Transmission Equalisation Adjustment (TEA)

The impact of the removal of the TEA on the difference between regional and metropolitan average network charges was analysed based on the 2006 Equalisation Adjustment, see Table 5-9 below.

The average impact (on a cents per kWh basis) on each distribution area across all customers was assessed by referring to the:

- equalisation adjustment (dollars per annum, GST exclusive)[34]; and
- an assumption of energy consumption (kWh)[35];

for each distribution area (refer Table 5-9 below).

Table 5-9: Impact of Equalisation Adjustment on a cents per kWh basis (GST exclusive)

	SP AusNet	Powercor	Alinta	CitiPower	United
2006 Equalisation Adjustment	($2,963,400)	($11,406,600)	$3,102,600	$3,552,000	$7,715,400
Forecast energy consumption (GWh)	7,374	10,024	4,213	5,702	7,665
Impact (c/kWh)	-0.04	-0.11	0.07	0.06	0.10

This analysis indicates that the impact on the difference between average network charges for regional and metropolitan customers of removing this adjustment would have ranged from 0.1

[34] VENCorp, Electricity Transmission Use of System Prices 1 July 2006 – 30 June 2007, published 15 May 2006
[35] Essential Services Commission, 2006 Electricity Distribution Price Review

to 0.21 cents per kWh (being the differences between the impact on Citipower and SP AusNet and the difference between United Energy and Powercor[36] respectively).

Table 5-10 shows the impact of the removal of the TEA on the difference between average network charges for regional and metropolitan businesses in the sample, using the difference between the impact for the relevant distribution areas where the businesses with lowest and highest average network charges are located.

Table 5-10: Removal of TEA – impact of difference in charges

	Average Network Charge (c/kWh)	
	Lowest	**Highest**
Regional (range in sample)	1.89	6.56
Metro (range in sample)	2.29	4.95
Comparison of lowest Regional to lowest Metro & highest Regional to highest Metro		
Difference between Regional and Metro (c/kWh)	*-0.40*	*1.61*
Difference between Regional and Metro (%)	*-17%*	*33%*
Estimated difference after backing out of TEA (c/kWh)	*-0.40*	*1.80*
Estimated difference after backing out of TEA (%)	*-17%*	*36%*
Comparison of lowest Regional to highest Metro & highest Regional to lowest Metro		
Difference between Regional and Metro (c/kWh)	*-3.06*	*4.27*
Difference between Regional and Metro (%)	*-62%*	*186%*
Estimated difference after backing out of TEA (c/kWh)	*-3.09*	*4.48*
Estimated difference after backing out of TEA (%)	*-62%*	*196%*

This suggests that if the TEA is completely removed, then the regional and metropolitan price differentials in the sample would increase by up to 9 percent of metropolitan network prices (on a cents per kWh basis).

We note that the TEA is an inter-network cross subsidy and can only have an impact on average network charges for businesses in different distribution areas, not on regional and metropolitan businesses in the same distribution areas.

Table 5-10 shows the impact on the average network charges for businesses in the sample, using the impact for the relevant distribution areas where the businesses with lowest and highest average network charges are located.

[36] Where SP AusNet and Powercor are regarded as being 'regional' and Alinta, Citipower and United Energy are regarded as being 'metropolitan'.

Table 5-11: Removal of TEA – impact on average network charges for businesses in sample

	Average Network Charge (c/kWh)	
	Lowest	Highest
Regional (range in sample)	1.89	6.56
Metro (range in sample)	2.29	4.95
Average network charge after backing out of TEA		
Regional (range in sample)	*1.79*	*6.67*
Metro (range in sample)	*2.19*	*4.88*

We note that the lowest average network charge after removal of the TEA is for a regional business in the sample. Again, this is due to the "regional" classification of a business in the sample that is sited in a satellite town of Melbourne and is connected to a distribution network that serves predominantly metropolitan customers.

The following tables show the dollar impact of the removal of the TEA on the annual network charges for the two illustrative examples provided in Section 5.1.3. We again note that these are illustrative examples only and that significant variation in the results can occur depending on the assumptions included in the analysis and how a distribution business may allocate the costs or benefits of the TEA among its tariff categories. We have made a general assumption that all customers within a network bear the average cost or benefit equally.

The analysis assumes the regional location is within Powercor's distribution area (which would increase average network charges by 0.11 cents per KWh with the removal of the TEA) and the metropolitan location is within Citipower's distribution area (which would decrease average network charges by 0.06 cents per KWh with the removal of the TEA).

Table 5-12: Removal of TEA – impact on annual network charges for Example 1 - Low voltage customer

Regional / Metro	Annual Network Charge ($)		
	Current	Without TEA	Difference
Regional	63,000	64,000	*1,000*
Metro	53,000	52,000	*(1000)*
Difference ($)	***10,000***	***12,000***	***2,000***
Difference (%)	***19%***	***23%***	***4%***

The impact of the removal of the TEA for the sample regional Victorian business in Example 1 (Low Voltage) located within Powercor's distribution area is estimated to increase its annual network charge by $1,000. In comparison, if that business were located in metropolitan Melbourne within Citipower's distribution area, there would be an estimated decrease in its annual network charge of $1,000. The differential between regional and metropolitan locations in this example is estimated to increase by a further 4% with the removal of the TEA.

Table 5-13: Removal of TEA – impact on annual network charges for Example 2 - High voltage customer

Regional / Metro	Annual Network Charge ($)		
	Current	Without TEA	Difference
Regional	226,000	236,000	*10,000*
Metro	172,000	167,000	*(5000)*
Difference ($)	***54,000***	***69,000***	***15,000***
Difference (%)	***31%***	***41%***	***10%***

The removal of the TEA for the sample regional Victorian business in Example 2 (High voltage) has a greater dollar and percentage impact that in Example 1, with the differential between regional and metropolitan locations in this example estimated to increase by a further $15,000 (or around 10 percent) than that exists currently.

5.2 Qualitative analysis – key findings

The key findings from the interviews with 10 businesses are provided below.

- None of the 10 businesses interviewed indicated that electricity costs were critical to their business location decision. Key influences cited by businesses included tradition or historical business location, access to customers and access to suppliers and raw materials. It is possible that heightened awareness of the locational differential in network costs could change this view.

- Reliability and quality of electricity supply was viewed as being important. Businesses interviewed were generally happy with current levels of reliability and quality. Some businesses reported that they have installed back up electricity supply, due to the nature of their business requiring continuous electricity and to insure against the risk of disruption to their operations.

- The sample was divided in terms of preference for reduced electricity prices versus improvements in quality and reliability with:

  - 70 percent preferring marginal reductions in price of electricity supply in favour of marginal improvements in quality and reliability of supply (on the assumption that current levels of quality and reliability of supply is maintained); and

  - 30 percent preferring marginal improvements in their quality and reliability of supply in favour of marginal reductions in price (with one business responding that they would be willing to pay more for better quality and reliability).

- Businesses interviewed commented that electricity costs were significant to their business.

- There was a general level of awareness amongst businesses interviewed of the components within total electricity charges; various tariffs that might apply to their business; and the regional/metropolitan differences in electricity network charges.

- There was a low level of awareness of Victoria's Transmission Equalisation Scheme and its unwinding amongst Victorian businesses interviewed. Of the nine businesses with operations in Victoria, only 22 percent of businesses interviewed were aware of Victoria's Transmission Equalisation Scheme and its unwinding, implying that the TEA is a hidden subsidy.

- Businesses in the sample are dependent on electricity as a source of energy and have no effective choice of alternative energy sources.

More detailed analysis from the interviews is provided in Appendix F.

5.3 Conclusion

In conclusion, the findings from the quantitative and qualitative analysis of information collected from businesses in the sample highlight:

- There is a cost impact on businesses being located in a regional area rather than in a metropolitan area. However, this cost impact can vary considerably across businesses according to level of consumption and load profile.

- The differentials between regional and metropolitan prices are not always clear cut. Intra-network cross subsidies appear to have resulted in instances in the sample where "metropolitan" businesses can pay higher charges than regional businesses. However, this does not alter the finding from the sample that in all States regional business continues to pay the highest network charges.

- Differentials in average network charges between businesses are due to a combination of factors, including the network a business is connected to, network tariff structure, load and consumption profile, not just business location.

- For the businesses in the sample, electricity prices did not provide an effective price signal for where to locate their business. Rather, the businesses in the sample do not appear to be in a position to provide an economically efficient response to locational network pricing differentials.

- The complete removal of the TEA would increase the size of the differential between regional and metropolitan businesses for the sample by up to 9 percent. However, we emphasise that this finding is illustrative and subject to the characteristics of the businesses in the sample. A different sample could provide different results.

6 A strategy to offset network cost differentials for regional business customers

6.1 Introduction

Section 4 of this report outlines the regulatory and institutional factors that have led to the situation portrayed in Section 5 which illustrates that, for the sample we reviewed, business customers located in regional Australia typically pay higher network charges than their metropolitan counterparts.

This section of the report outlines and reviews potential strategies that the City of Greater Bendigo might adopt to seek mitigation of these price differentials.

6.2 Framework for assessing strategies

We suggest that a price mitigation strategy that might meet the City of Greater Bendigo's objectives ideally would have the following characteristics. It would:

- reduce or obviate the impact on regional business customers of locational network price differentials;
- not promote the interests of one group of customers at the expense of others;
- have a sound economic rationale or basis to it;
- be acceptable to governments;
- be acceptable to network owners and operators;
- be saleable to regulators and consistent with their regulatory objectives;
- be capable of practical implementation in the near to medium term; and
- have the potential to operate successfully.

Sections 6.3 to 6.7 below describe a number of potential options for mitigating price differentials. Section 6.8 summarises each option against these criteria.

6.3 The "do nothing" scenario

It would seem reasonable to assume that differentials between regional and metropolitan pricing will continue on the basis that the current regulatory regime and pricing principles of cost reflectivity continue to be applied.

Some of the cross subsidies currently in place will unwind. In Victoria, the TEA will fall away by 2020. Section 4.3.2 illustrates the effect of this.

Also in Victoria, the initial vesting asset values and the adjustments made on vesting (described in Section 4.3.1) will become fully depreciated, possibly over the next 20 years or more. Section 4.3.1 also illustrates the effect this may have on asset values and prices. Section 4.3.4 describes a similar mechanism in NSW. NSW may experience a similar effect to Victoria on the basis that the government as shareholders has borne a write down of some of Country Energy assets at least, but over time, these assets will require replacement.

In Queensland, it would seem reasonable to conclude that, where these businesses may compete against others located in metropolitan areas, these cost differentials would need to be absorbed by the businesses and their investors, or by local customers, where those customers may have no effective choice of supplier. There appears to be a significant cross subsidy between the two electricity distribution networks, to equalise locational costs. However, this is effectively at the retail level and, with the imminent introduction of FRC and the sale of the government's retail interests, this appears difficult to continue in its present form. The future of this cross subsidy is not known to us at the time of writing, although in principle it might be continued if the government as shareholder, were to merge the two networks for example.

However, other intra-network cross subsidies, notably 'postage stamp' pricing and distribution loss factors which are firmly entrenched in the pricing mechanism, appear likely to remain in the foreseeable future.

In summary, under the current arrangements, one might reasonably expect to see the existing geographic differentials in network prices in the NEM be maintained or increased as a number of cross subsidies are unwound.

6.4 Potential options for change

We summarise below:

- the economic arguments for the basis of cost that might underlie electricity network prices; and

- the strategic options for addressing regional disparities in prices.

Electricity networks are generally regarded as monopoly, bottleneck facilities that are often uneconomic to duplicate. In order that they cannot use their monopoly status to abuse market power, they are often the subject of economic regulation.

In determining reasonable prices for access to electricity networks in regional areas of Australia, simply taking the full costs of service provision – including the cost of past investment in transmission infrastructure – and incorporating these into access prices will not necessarily lead to efficient economic outcomes.

In the case of regional electricity network infrastructure, the past investment and location decisions that have been made are "sunk costs". Sunk costs are costs that have been incurred in the past and cannot be recovered. This is true in the case of electricity network assets in the sense that, once they have been constructed for a particular use, in a particular location, they cannot be diverted to other uses.

With price regulation of networks, regulators generally seek prices that are reflective of efficient costs. This reflects the view that in competitive markets prices will, over time, be set at levels that are close to the most efficient cost of delivering the good or service. In many competitive markets, this could mean pricing at close to the marginal cost of production.

Although marginal cost pricing might be the level that attains the greatest level of economic efficiency in capital intensive industries like electricity transmission and distribution network industries, marginal costs are relatively low compared to the long run average cost of providing a service, which includes the heavy fixed costs of infrastructure. If a regulator sets prices at levels that reflected only the short run marginal costs of provision then network owners would have little incentive to invest in infrastructure in the future.

In the case of the existing regional electricity network, it can be said that outcomes will be economically efficient as long as network prices cover the short run variable costs of their operation. As long as these costs are recovered by the network operator then the existing network as it stands will be used and economic efficiency achieved. Even if these prices do not generate any return on previous capital investment, it will pay the network owner to continue the operation of the network as the network is "sunk" and cannot be used for any other purpose.

Indeed if prices are raised substantially above these levels then businesses in regional areas may curtail their use of electricity and the network would not be used as much as could be economically justified. Higher prices and lower demand would not mean that these assets could be turned to other uses. Instead, they would simply remain under utilised in their present location. For the existing network, economic efficiency is achieved by pricing at a level that at least covers marginal costs.

Looking forward, however, any new investment in network augmentation would need to recover revenues that covered the full, forward looking long-run incremental costs of provision. New investment in transmission networks does not involve sunk costs until they are undertaken and, in order to provide network providers with sufficient incentives to invest in network augmentations, they would need prices that cover the long run, forward looking, incremental costs (including capital costs).

From this, we can conclude that it is quite possible that the pricing of access to networks could be different depending upon whether we are looking at access to old networks with substantially sunk costs or, alternatively, to new investments.

Bearing these points in mind, the ending of the Transmission Equalisation Adjustment Scheme and the unwinding of other network cross subsidies could potentially lead to problems.

If prices of access to the existing regional networks are allowed to rise to cover some notional level of capital costs then use of these networks could be underutilised. The networks cannot be

diverted to another use because of their "fixed" nature and so any pricing that was substantially above short run marginal costs could lead to economic, inefficient outcomes.

In dealing with this pricing problem, there are three potential solutions:

1) a regulated outcome that lowers regional network prices down towards that of marginal costs without any compensatory price rise or income to the network owner elsewhere;

2) a regulated outcome such as the TEA, which lowers prices to regional users but comes at the expense of users elsewhere on the network; and

3) a CSO payment from budget which enables lower network prices to regional users without raising prices to other network users.

We examine each of these options below.

6.5 A regulated outcome which lower regional network prices towards of marginal costs without any compensatory price rise or income to the network owner elsewhere

Although there is some economic justification for this approach, it does raise the problem of regulatory risk. In the case where assets have been privatised, the new private owners paid sums to the government for the assets on the expectation of a particular rate of return. By arbitrarily taking this away from them, it creates disincentives to investors in infrastructure in Australia by heightening the impression that they will be the subject of "regulatory risk" in the form of abrupt changes to regulatory outcomes.

There are other implications too:

- this approach provides network owners with strong incentives to reduce total cost. This may increase the risk of reduced service standards;

- there is not a geographical or regional rationale for this approach. In other words, if one accepts that for sunk assets only marginal costs should be recovered, that economic argument would apply equally to all customers irrespective of geographic location. While this approach may argue for a reduction in prices to customers in general, it does not address specifically regional pricing disparities, except to the extent that the differential in marginal cost may be less than the differential in long-run, incremental cost;

- under a national regulatory regime administered by the AER, one would expect to see consistency in regulatory approach throughout the NEM. Therefore while some networks may currently be in government ownership, such an approach:

  - would not discriminate between government and privately owned networks; and

  - could be opposed by governments that might foreseeably contemplate privatisation of electricity assets, since it would reduce potential capital value of the networks.

We emphasise strongly the issue of 'regulatory risk' this approach entails. A change in network pricing approach that reduces returns to investors below current levels would almost certainly be regarded by capital markets as providing a disincentive to investment and may adversely impact the appetite of investors to invest in new infrastructure. (The precedent may also create flow on effects to investment in other access regulated infrastructure such as gas, water and telecommunications assets for example.) One would expect it to be strongly opposed by asset owners who would have reasons to invest strongly in presenting arguments and lobbying against such an approach. On this practical basis alone, it may be difficult to win.

Regulators also have a general obligation to balance the interests of customers and investors. Accordingly, one could assume that a regulator would be swayed by a marginal cost argument, without having regard to the interests of investors that may be prejudiced by such an approach.

In summary, this approach:

- has a validly arguable economic underpinning; but
- is one of a range of alternatives for how cost may be attributed to customers. It does not provide a unique solution;
- would require a transfer of value from network owners (be they government or private) to customers;
- may provide benefits for all customers but does not specifically distinguish between regional and metropolitan customers; and
- even if such a scheme were put in place at the potentially significant cost to increase regulatory risk, the scheme would itself be inevitably phased out, over the period in which 'sunk' investment is retired and replaced by new investment.

6.6 A regulated outcome such as the Transmission Equalisation Adjustment, which lowers prices to regional users but comes at the expense of users elsewhere on the network

This form of approach equalises prices across networks, safeguards the revenue of the owner, and constrains prices to regional users but does so at the expense of other network users. In doing so, it over prices some classes of users which creates inefficiencies by deterring demand or inefficiently pricing for electricity on parts of the overall network. Despite these problems, this form of approach is not uncommon in Australia. In the case of telecommunications and postal services, for instance, regulated prices of services of the fixed line network of Telstra and of reserved services for Australia Post allow for the recovery of enough revenue to pay for regional services at standard prices across regional and urban centres.

Generally, the cross subsidies that are built into this form of pricing are not based on explicit economic justification but instead are justified on the grounds that it is equitable for people in regional areas to have access to a similar level of communication services as those who live in urban areas.

It would have to be said that generally there is no specific economic rationale for this sort of assistance, especially in the sense of favouring industries for whom the benefits of cross subsidised assistance exceeds the costs but instead is justified on grounds of equity and access.

6.6.1 Is there scope for this under the regulatory framework?

It is difficult to find an opportunity within the National Electricity Rules (NER) for a form of price adjustment that does not have a basis of efficient economic cost. We outline some of the regulatory issues below.

While Victoria's TEA for example, is inconsistent with the NER's requirements, it is accommodated within the regulatory framework by a legislated derogation from the NER[37]. This derogation is a historic legacy because the TEA was enshrined in Victoria's regulatory framework which predated both the NER and their predecessor, the National Electricity Code. The purpose of the TEA was not to insulate customers from cost reflective pricing. Rather, it was to gradually phase in the price differentials that more cost reflective pricing may produce. In other words, the TEA might be seen as pricing imperfection that has a pragmatic rather than an economic basis, and is being phased out.

The recent revisions to the regulatory regime within the NEM would imply that, if the TEA were to be prolonged, retained or a similar arrangement instituted nationally, a further derogation[38] would be required, which presumably would be effected through the National Electricity Law and would require initiation at the MCE level rather than at the jurisdictional level.

6.6.2 What are the regulatory issues?

This form of pricing support is likely to be contrary to the principles of cost reflectivity which underlie the regulatory framework and the purpose of many of Australia's energy market reforms. For example:

- accurate information about the costs of service provision, and the provision of efficient returns based on those costs, is generally seen by regulators to be vital to informing efficient investment decisions for the benefit of the entire economy. For example, if prices do not recover costs, there may be little incentive to invest in maintaining or improving the network. On the other hand, if costs are overstated, prices to customers may be excessive and provide incentives for inefficient or unnecessary investment in assets and services;

- it is important for costs and prices to be attributed accurately between the different components of electricity supply such as networks, generation and retail. If the cost or price of any component is distorted by a cross subsidy then this may send inappropriate or inaccurate price signals. For example, enormous effort and cost has been expended in recent years to introduce full retail contestability into electricity supply and this is being

[37] Refer to clause 9.8.4 (a)(3) of the NER
[38] However, we emphasise that we do not provide legal advice , which should be sought before this statement is relied or acted on.

increasingly supported by the introduction of interval or time of day use, electricity meters. A purpose is to provide customers with prices that provide fairly stated price signals[39] and investment signals for all sectors of the supply industry. A cross subsidy that may distort those costs or is not transparent, may prejudice these objectives.

This does not necessarily argue against forms of pricing support, but does argue that where they may exist they should be transparent and well understood. There is a risk that, if a cross-subsidy or pricing support were accounted for within a cost and were not transparent, it could distort the price signal. A drawback of the TEA is that for most customers it is neither transparent nor evident. As part of the development of Australia's National Competition Policy in the mid 1990s, the Council of Australian Governments (COAG) stated that, for purposes of competitive neutrality, governments are free to determine who should receive a CSO payment or subsidy, but that such payments or subsidies should be transparent, appropriately costed and directly funded by government. This has meant that over the past 10 years there has been a general trend towards greater, rather, than less transparency in the payment of cross subsidies; and

- entrenching a cross subsidy or support into one element of the total cost of supply, such as network prices, may not be the most flexible or useful way of providing support. Supporting network prices implicitly assumes that the most efficient way for regional customers to access electricity supply is to continue to use the network at existing or higher levels of service. If this assumption ceases to hold, even the customers intended to benefit from the subsidy may be disadvantaged. For example, if carbon price signals are introduced then these, particularly in combination with the higher loss factors of regional networks, could provide incentives for regional customers to make greater use of dispersed generation sources. (For example localised generation or site specific solar power.) This could reduce access to any cross subsidy that might be embedded in the network prices but provide incentives counter to the intent of carbon price signals, to continue to access less cost (and environmentally) efficient sources of generation.

An inter-network cross subsidy may be difficult to refine in a way that focuses the benefit on those it is intended to help. For example Section 4.3.2 shows that the TEA operates to provide cross subsidies between different and adjacent distribution areas. However, distribution areas tend to provide broad, not precise, alignments between regional and metropolitan customers. The following example illustrates the implications of this.

[39] By 'price signal', we mean a signal sent to consumers that may provide an economic imperative for influencing this behaviour.

Case study

The boundary between Powercor's and Alinta's distribution areas runs through Melbourne's western suburbs. The consequence is that, for example, customers on the western side of Burnett Road in Sunshine are potentially subject to the same network charges as regional customers in Powercor's area, while customers on the eastern side of Burnett Road are subject to Alinta's (metropolitan) network charges. This is because of the geographic cross subsidies that arise from the application of 'postage stamp' pricing to each distribution area.

The geographic divide represented by the width of Burnett Road for example, should not be so great as to cause intrinsically different costs of supply to each side of Burnett Road. However, the following example illustrates that the differential in network charges is potentially significant.

For example assume a customer with the following characteristics.

Peak	126,000	kWh per month
Off-peak	112,000	kWh per month
Total Energy	238,000	kWh per month
Typical annual consumption	2.86	GWh per year
Maximum demand	443	kVA

We illustrate below how the network tariffs applicable to that customer might vary between Alinta and Powercor's distribution areas.

Distribution business		**Alinta**	**Powercor**
Assumed tariffs*		**A340 Low Voltage (Large Business)**	**DL Large Low Voltage Demand**
Standing charge	$/customer pa	4,906	
Peak rate	c/kWh	2.15	2.77
Off-peak rate	c/kWh	0.741	1.51
Demand rate	$/kW pa	66.14	86.40
Standing charge	$/month	409	-
Energy charges	$/month	3,539	5,185
Demand charges	$/month	2,440	3,187
Total monthly charges	$	$6,388 pm	$8,372 pm
Difference		31%	

We note that Powercor's DLA and DLC tariffs offer alternatives to the DL tariff illustrated above. However ,all still indicate differences of the order of 27% to 31%.

* Source: ESC Approved network tariffs for 2007

The cost is higher for the Powercor customers largely because, unlike Alinta's customers, they share in higher cost of supply to regional areas. This results in pricing differentials at the boundaries between distribution areas for adjacent and potentially identical customers.

The TEA helps to mitigate differences in network costs not only for Powercor's regional customers, but also its metropolitan customers in Sunshine.

Therefore, while there may be an economic argument to unwind the TEA, on the basis of providing more cost reflective pricing, cost reflective pricing does not apply equally to all customers. This example shows that for some customers in proximity to the boundaries between largely regional and largely metropolitan areas, unwinding the TEA reduces cost reflectivity and increases price inequity for those customers. However, this situation only comes about because in this example the TEA serves to transfer the cost of subsidising regional network customers from Powercor's metropolitan to the customers of another distribution area.

6.6.3 What are the arguments in favour?

The above discussion suggests that one is unlikely to find a regulatory based mechanism to introduce an inter-network cross subsidy such as the TEA within the NEM. However, we suggest that the imperative for greater equity between regional and metropolitan prices is based on broader considerations which the regulatory framework for network pricing does not readily accommodate.

The arguments for greater network pricing equity may include suggestions that:

- the social and political imperatives of more uniform geographic pricing outweigh the imperatives of using network prices to send locational price signals to customers. This assumes that in reality few customers are influenced in their choice of location by network prices. Rather for most customers, their choice of location is a 'sunk' decision made before any locationally cost reflective element was introduced in network pricing. The discussion in Section 6.5 describes the regulatory risk of investors being prejudiced if the basis of their investment decisions were to be changed. There may be an analogous argument that the introduction of locational price signals, subsequent to customers having made a locational investment decision, is a regulatory risk borne by customers. That is, they are costs imposed on regional businesses subsequent to investment by customers.

  We do not suggest that it would be realistic to argue that no customers are influenced by locational network price signals. For example, for large high voltage customers who may be connected directly to transmission networks, transmission costs and their associated locational price signals may be very important to determining where to invest. However, none of the sample of businesses interviewed for this study, indicated that network costs provided an effective locational price signal. In the absence of evidence to suggest that most customers (business or domestic) respond to locational price signals, one might conclude that in practical (as opposed to theoretical) terms many businesses and regional economies may have little practical capacity to respond to locational price signals in a way that may be economically efficient (such as relocating or investing in other markets where it may be economically more rational to do so);

- it could be argued in some cases that in practical terms it could even be undesirable for businesses to respond to locational network price signals. A regulatory economic argument might argue that an appropriate response to locational price signals would be for electricity network customers to locate where they are best able to recover costs and maximise returns. However, in practical terms, such a response would have economic and social costs and impacts broader than those taken into account when network prices are determined. For example the withdrawal, reduction in activity or relocation of a business from a regional area, could have a significant adverse effect on the local economy. This impact might be reasonably expected to reflect the greater sensitivity of regional areas to the performance of individual businesses. Metropolitan areas tend to be more densely populated with businesses and there are generally greater opportunities for the local economy to diversify the risk of variations in economic performance, and for example to absorb surplus labour; and

- the implications of regional businesses bearing these costs.

We expand on these matters further in Section 6.7.

6.6.4 Summary

A regulated cross subsidy which lowers network prices to regional users at the expense of users elsewhere on the network appears problematic because:

- it spreads the benefit of the cross subsidy across users within a network, regardless of whether they may be metropolitan or rural customers. It may be difficult to focus the benefit of the cross subsidy on intended target customer groups (such as regional businesses) within a network;

- while there are existing locational cross subsidies within a distribution network as a result of postage stamp pricing, an inter-network cross subsidy would also increase prices for customers of other networks above levels that would otherwise be charged;

- it is not clear how a cross subsidy between networks and one that does not have a basis of network cost, could be accommodated within the regulatory framework;

- a cross subsidy that distorts costs may distort investment decisions and potentially benefits to customers; but

- there are arguments that the regulatory model of cost reflectivity does not fully account for the broader and practical economic costs and impacts of locational investment decisions; and

- where this may argue for a form of pricing support, that support should be transparent and separate to the costs of each component of service.

These points suggest that the use of regulatory network pricing mechanisms to establish inter-network cross subsidies may not be a practical option.

This leads us to consider an option that does not rely on cross subsidisation or a significant change to existing pricing arrangements.

6.7 A payment from government which enables lower network prices to regional users without raising prices to other network users

Section 6.6 argues for mitigation of regional network prices, but at the same time explains that:

- the case for this has a broader scope than the regulatory pricing framework for electricity networks;
- it appears neither practical nor desirable to argue that the costs of the components of electricity supply should be changed to achieve this;
- the fact that regional customers may have a limited capacity to respond to higher network costs does not of itself support an argument that metropolitan customers should bear inefficient costs; and
- it is not clear how a scheme that creates cross subsidies between networks could be accommodated in the regulatory framework.

We suggest an option such as a Community Service Obligation (CSO) could be considered to overcome these obstacles. By CSO, we mean a payment provided by government to meet costs of supply that might not be met by prices charged to regional customers.

By definition, a CSO normally refers to a payment that does not have a commercial or market basis. However, we explain below that the criteria could be set such that the payments may be expected to have a net economic or social benefit. In which case, a term such as "Regional Network Fund" (or RNF) may be more appropriate than CSO.

We emphasise that the explanations and suggestions set out below are at this stage conceptual. Significant further work and consultation with governments and stakeholders would be necessary to develop all aspects to the level of practical implementation detail. Rather, the objective of this report is to provide the City of Greater Bendigo with a strategy for moving forward with advocacy.

6.7.1 What would be the rationale for the payment?

The payment could be made where regional network expenditure may provide opportunities to:

a) stimulate regional economic growth; or

b) avoid opportunity costs to governments or regional economies.

The payment would be aimed at offsetting differentials between regional and metropolitan network costs to achieve criteria a) or b) above. The RNF could provide payment in two forms:

- a government contribution to network expenditure; or

- CSO-type payments to offset the differential in regional and metropolitan network supply costs.

In the remainder of Section 6.7, we explain how it may be possible to develop business cases to support payments for specific network expenditure. This has the advantage of justifying the payment on an economic basis increasing the probability of acceptance of the scheme where governments need to make decisions about the allocation of limited funds.

A business or economic case for tariff support may be more difficult to predicate on electricity network costs alone, if it is not readily identifiable with and hence justified by specific expenditure and benefits.

While we have outlined its inclusion in the RNF, we suggest that for this form of payment to be sustainable, it would need to be justified on the basis that regional businesses as a whole are disadvantaged by their location. This issue is not unique to electricity network costs but impinges on a wide range of costs faced by regional businesses. We therefore suggest that a case for tariff support might be made as part of a more general case for support to offset the adverse economic impacts of higher costs experienced by regionally located businesses.

The amount of the payment from consolidated revenue would be justified or constrained by assessments of:

- the economic impact that the payment might reasonably be expected to trigger (this is a common rationale for government support for major sporting events for example); or

- the present value of the broader economy-wide costs avoided by the payment.

We provide the following selective illustrations of how these principles may be applied.

Network expenditure

- Because of the physical characteristics of extended regional networks, providing regional customers with service standards equivalent to those of their metropolitan counterparts can be more challenging and expensive. However, with increasing technological sophistication and reliance by customers on improving network service standards, regional business customers may experience competitive disadvantage with consequential adverse regional economic impacts, if they are unable to access network service standards that may keep pace more closely with service standard improvements in metropolitan areas. A government contribution could help to secure these improvements. The existing regulatory mechanism works such that capital contributions to networks reduce the tariffs customers would otherwise pay. We explain this in more detail below. An assessment of adverse economic impacts if the investment did not proceed may justify or set limits on levels of government contribution to investment to help improvements in regional service standards. One could argue that it is properly the role of the network business to deliver service standards that meet regulatory expectations. This is true but to the extent it is necessary for

a network business to incur efficient cost to deliver on this, that cost would, subject to regulatory approval, normally be passed through to customers in the form of regulated tariffs.

- Bushfire mitigation is a more significant cost for regional networks than for metropolitan networks. The greater costs of regional bushfire mitigation are passed back to the customers of regional networks through cost reflective tariffs. However, where power lines may trigger bushfires, there are adverse regional economic impacts and the costs to government of tackling the bushfire and its consequences can be considerable. It may be reasonable to consider whether in some areas, the costs of undertaking prevention measures in excess of the minimum mandated requirements, would be justified by a reduction in the expected costs and triple bottom impacts of subsequent loss and mitigation if the additional prevention did not occur.

- Where there may be a new commercial investment, such as a new or expanded factory or business park, which could require the construction of new assets or system augmentation, a government contribution to the capital costs of that augmentation might be considered. From the government's standpoint, the economic justification for the payment would be the positive regional economic impact of securing commercial or industrial development in a regional area. For the network customers making the commercial investment, there would be a reduction in capital contribution costs that would help to offset the present value of the greater network charges they face from investing in a regional area. This example could also be applied to transmission networks where high voltage customers may face connection asset charges and locational charges, according to where on the network they may be sited.

Tariff support

There may be two strands to the argument for this form of support:

- Firstly, a potential general economic argument that higher recurring electricity prices may depress business activity in regional Australia, with broader adverse economic outcomes for regional economies. However, significant further work may be required to demonstrate this. The limited sample interviewed for this report provided insufficient evidence to mount a general case for this assertion. While it is clear that in general regional electricity prices are higher, the causal effects of this are more difficult to evidence in general terms. It may therefore be more effective to seek support for the adverse impact of higher regional tariffs in general as part and parcel of a broader package of evidence concerning the costs of business in regional Australia; and

- There may be an argument to seek a CSO to offset these costs. A CSO normally refers to a payment to support the delivery of a service that would not otherwise be economically sustainable. The CSO in Queensland and the Victorian Network Tariff Rebate assist with the delivery of an essential service to all customers. A more targeted CSO to regional business customers would need to be based on the premise that higher regional electricity prices result in regional businesses bearing economically unsustainable costs, and consequently CSO payments are required to:

  - prevent businesses exiting regional economies or reducing activity; or

- assist businesses to continue to trade and support the regional economy and social structure by providing benefits such as employment and wider economic growth in the community.

To be successful, this approach is likely to require:

- a significant body of evidence to demonstrate that electricity network prices lead to most regional businesses meeting one of the two CSOs summarised above; and
- political goodwill.

6.7.2 Who would receive the payments?

Network expenditure

We suggest that for one-off contributions for network expenditure:

- the *payments* would necessarily be made to the relevant network business as it would be responsible for the network expenditure the payments would support; but
- the *benefits* would be intended to accrue to regional business customers. We explain this point below in Section 6.7.3.

However, if the scheme is to be practical, there would need to be reasonable incentive for network businesses to participate to deliver additional benefits to customers. We outline the incentives for network businesses, provided by the existing regulatory framework and the proposed scheme, in Section 6.7.4 below.

Tariff support

We suggest that for CSO-type payments:

- the *payments* could be made to the relevant network businesses but credited to relevant business customers; but
- the *benefits* would accrue to regional large business customers through a reduction in network tariffs.

6.7.3 How would regional business network customers benefit from this?

Network expenditure

Depending on the nature and purpose of the payments, there are a number of different ways in which customers could benefit from such a scheme under the existing regulatory pricing framework.

For example:

- where a network business builds or augments a network asset specifically to serve a customer, it normally seeks a customer contribution to meet the cost of that asset. The network business however, must deduct the value of that customer contribution for that asset from its regulatory asset base. Consequently, it receives no income (return on and of capital[40]) for contributed value. It also means that:

  - the customer for whom the asset is built, pays a one-off upfront cost;

  - the customer then pays network tariffs on the same basis as similar customers of that network, notwithstanding that an asset has been constructed specifically for that customer; and

  - network customers in general do not have to pay for the cost of that asset because its cost has not been included in the network's regulatory asset base.

  Accordingly, if a government payment was to contribute to the capital cost of a customer specific asset, the customer's network tariffs would not change but the customers for whom the asset is constructed would benefit directly by the amount of the payment;

- if the capital contribution were to be for a non-customer specific asset such as asset augmentation to improve service standards, then the government payment would offset the cost of that asset expenditure and hence reduce the costs and tariffs that customer would otherwise bear to facilitate improved service standards. In this example, the reduction may be spread over the population of customers more broadly and not be constrained to business customers; and

- there are well established mechanisms for dealing with customer contributions to capital expenditure. However, contributions to operating expenditure are less common. It would seem reasonable to expect the regulator would seek to reduce the costs passed through to customers in regulated tariffs, by the amount of the contributions. However, if a scheme were to be instituted, the regulatory treatment would need to be agreed in advance. We explain some of the associated issues below.

Tariff support

Regional network business customers could also benefit from a CSO-type payment with the intent of general reductions in existing tariffs, where the government may believe that there is a justifiable case for this. However, we suggest that in practice a general subsidisation of regional business tariffs might be a less "saleable" proposition because:

- payments intended to support regional business customers in general without reference to specific investments may:

  - require more money; and/or

[40] Refer to Appendix D.

- be diluted to the point where they may provide few, if any, larger business customers with a material or noticeable benefit;

- funding targeted at those investments and projects most likely to deliver regional economic benefits may be more efficient and be more "saleable" to government than a more general scheme;

- a more general scheme may not readily allow benefits to be focussed on regional areas that may have particular needs within broad network areas. As we explain elsewhere in this report, network area boundaries do not always align with boundaries of metropolitan, regional or remote areas;

- there will be constraints on the funding available for a scheme of this nature. Focusing the payments on specific new network investments may make it easier to develop economic or financial cases for payments which in turn may increase the justification for payments and hence the total potential funding available to support regional customers; and

- a more focused, case by case basis may be less of a budgetary risk for government than a broader commitment. It provides government with control over the amount of payments according to current budgetary constraints and regional economic development imperatives. This may not appear to be an immediate concern for regional business customers who may seek the benefits of any funding. However, we suggest that it would be in the interests of those customers for any scheme to be attractive and workable for government as a long-term proposition.

6.7.4 Why would a network business wish to participate?

Network expenditure

Section 3 has explained that the regulatory framework operates largely on the premise of reimbursing network businesses for efficient economic costs. Therefore, one might reasonably ask why a network business might wish to participate in a scheme which might reduce its regulated costs and tariffs. We suggest that:

- for capital contributions, the scheme could facilitate network investment that would not otherwise take place. While a network business does not earn returns on and of capital for contributed assets paid for by customers (or perhaps a government contribution), the additional capacity or load provided by the new connection allows the network business to utilise the existing network more efficiently. For example, a distribution business regulated by price cap, may be able to increase its revenue by increasing load (but not tariffs). This explanation applies to existing capital contributions and is not contingent on who pays the contribution (government or customers);

- the question of how to provide any necessary contributions to operating expenditure is less well established. In principle, a regulator may seek to reduce a network business' allowed operating expenditure by the contribution received. In which case, a business may be at best indifferent to this proposal. However, we suggest that, if the payment is intended to

increase network load, or utilisation, this may provide sufficient incentive to network businesses, for the reasons explained above. If the payment is intended to improve service standards, the interaction with any existing service standard incentive scheme would need to be considered; and

- regulators often have in place service standard incentive schemes where network businesses may increase or decrease their charges according to their historic performance against agreed service standards. One might expect that a regulator may be concerned that a contribution which would allow a network business to increase service standards above minimum levels could unduly benefit the business and not the customer - once by the receipt of any operating expenditure contribution that would reduce the network business costs, and once by any performance incentive payment included in customer tariffs, which might be achieved as a result of the contribution. Some detailed work would be necessary to ensure that the service standard incentive scheme appropriately compliments any regional network development payments intended to raise service standards, to provide an appropriate allocation of benefits to customers and incentives to businesses to deliver those benefits.

Tariff support

For CSO-type payments with the intent of general reductions in existing tariffs, a network business could benefit from:

- reducing the risk that their existing customers may relocate or downsize their operations or that potential customers may choose not to locate in their distribution area and therefore reducing network load or utilisation; and

- increased load and utilisation of its network, from existing business customers.

6.7.5 How would the amount of any payment be determined?

Network expenditure

The regulatory regimes that govern network pricing in Australia generally seek detailed examinations of network cost, often to assist the regulator to understand how closely actual or forecast costs align with ideally economic efficient network costs. While in making any payment, the government might reasonably expect assurance that it is not contributing to unnecessary or excessive cost, we suggest that the payments could not be predicated on government scrutiny of detailed network costs. This is because government as a funder would be 'purchasing' the wider economic benefits likely to result from the network expenditure, not the costs that provide the benefit.

A more intrusive analysis of the underlying costs of the network expenditure could:

- introduce unnecessary and avoidable administrative and financial complexity;

- cause government to participate as a de facto regulator, which would be an inappropriate and unnecessary role. The regulatory framework already provides controls over the efficiency of costs including those of contributed assets; and

- provide network businesses with incentives to deliver cost not benefits, and 'game' the process.

We suggest that in broad terms a Regional Network Fund could have the following characteristics:

- a Regional Network Agency might comprise or oversee several network specific decision-making Boards specific to each network that serves regional business customers;

- each Board might comprise government representatives and independent members including those with relevant technical and economic skills. It would be the body responsible for granting regional network development payments. The Board would consult with network businesses and regional business customers, but those parties would probably not be on the decision-making body because of the potential for conflict of interest;

- any relevant stakeholder (eg regional business customers, local government or network businesses) could make project specific submissions or applications for funding to the Board. The Agency or Board would publish criteria that submissions would need to demonstrate that they fulfil to be considered. One might expect that these would include economic, social and environmental criteria;

- the Board would undertake independent scrutiny or comparison of submissions to help it assess and prioritise applications for funding;

- the amount of the payment would be justified in terms of how it relates to anticipated regional economic outcomes, rather than by reference to the underlying costs of a network business; but

- it is likely that in return for the payment the Board on behalf of government might reasonably expect payment to be contingent on certain criteria being met (such as timing of investment and completion of associated commitments by customers or the network business).

We emphasise that, as with all other aspects outlined in this section, these things would need to be worked through in more detail and in consultation with all relevant stakeholders before developing detailed implementation proposals.

Tariff support

A general case for the economic detriment of higher tariffs would need to be made, probably by undertaking economic modelling of the economic impact for regional areas within each jurisdiction. This may be more difficult and less certain than the case-by-case approach supported for network expenditure support.

6.7.6 Who would provide funding?

The scheme outlined above implies that jurisdictional governments would be principal providers of funding in their roles as facilitators of regional development and potential beneficiaries of avoided adverse economic impacts. However, the Commonwealth Government is also likely to have an interest in the outcomes of regional network development and might be anticipated to have an interest to contribute to funding. It may also be possible for local government to have an interest. The interests and appetite of different levels of governments for participation would need to be established at an early stage.

We also comment that one might imagine an arrangement where it would not be necessary for all jurisdictions to participate or participate to the same extent, in order for some jurisdictions to provide Regional Network funding. This is because, where funding may come from jurisdictions, it would be expected to be applied to customers in those jurisdictions.

6.8 Conclusions

Table 6-1 below summarises each of the options considered against the assessment criteria suggested in Section 6.2.

The scope of our work does not extend to assessing the acceptability of these options to the stakeholders listed in Table 6-1. Rather, we have indicated factors those stakeholders could take into account when assessing options.

Table 6-1: Assessment of strategic options

	Do nothing	**Regulated reduction in regional network prices to marginal costs**	**Regulated inter network cross subsidy, such as the TEA**	**Regional Network Fund**
Reduces or obviates the impact on regional business customers of locational network price differentials	No effect	Could reduce prices for all. May reduce differentials too.	Yes – Benefits may not be constrained to regional customers.	Could offset effect for some but not necessarily all regional business customers.
Does not promote the interests of one group of customers at the expense of others	Allocates costs to regions. Maintains intra regional cross subsidies.	Would be funded by investors not customers.	No – Requires customers of some networks to bear additional cost.	While costs may be met from the general tax base they would be incurred in expectation of a net benefit.
Acceptable to governments	Consistent with current arrangements and policy.	Could be opposed because of the detriment to future investment it could provide.	Counters intent of reforms and NER, but may be politically attractive to some.[41]	Potential to provide economic and social benefits.
Acceptable to regulators	Consistent with current arrangements.	Regulators are obliged to balance interests of both customers and investors.	Would not be cost reflective. Counters intent of NER.	Should be consistent with existing framework. May not be contingent on regulatory approval.
Capable of near to medium term implementation	Yes – Already in place	Could not be done before next price reviews.	Would require changes in NER and regulatory attitudes.	Yes if there is government political support. Should not require institutional change.
Potential to operate successfully	Yes – based on precedent.	Yes if regulated, but could be subject to legal challenge by network owners and operators. Would unwind over time.	Only if significant regulatory obstacles can be overcome.	Could be accommodated by existing framework. Can be implemented with significant flexibility.
Acceptable to network owners and operators	Yes – subject to normal regulatory debate.	Likely to be strongly opposed on basis of sovereign risk.	Unknown – May be favoured by 'rural' networks if it maintains or stimulates network growth.	Unknown – May be favoured by 'rural' networks if it stimulates network growth.

[41] We note the MCE's recent announcement that it has asked the SCO to develop a work program including a review of all remaining derogations from the national framework, which would include the TEA. However until the scope of the work program is known it would be premature to speculate on the impact this may have on the TEA and its continuation.

We conclude that the concept of a Regional Network Fund may offer the City of Greater Bendigo a more practical approach to achieving its objectives of reducing the impact of regional network pricing disparities, than alternatives that may require significant changes to the basis of network pricing within the NEM.

6.9 Next steps

On the basis that the City of Greater Bendigo wishes to pursue the concept of a Regional Network Fund, we suggest that the key subsequent steps might comprise:

- prepare a concise position paper that spelt out scope imperatives and benefits and risks of schemes. This could include examples of specific regional economic benefits or avoided cost and consult with and canvass support with:
  - jurisdictional and Commonwealth government agencies interested in regional or rural development;
  - network businesses and regional business customers; and
- use consultation to refine proposals and gain government and stakeholder support, including potential future governments.

We envisage that the scheme itself would be sponsored and implemented by government, either at the jurisdictional or national level. The City of Greater Bendigo's advocacy would have the objective of triggering that commitment which would then allow the in principle proposals to be developed into a practical implementation plan.

6.9.1 Which government agencies would the City of Greater Bendigo approach?

We observe that:

- the RNF is based on imperatives of regional economic development not accommodated by the more limited scope of the regulatory framework for network pricing within the NEM; and
- would be intended to produce outcomes that offset the cost attributions of the regulatory framework for the NEM.

Therefore it may not be viable to anticipate that this concept would be best promoted by the Ministerial Council on Energy (MCE). This is because the MCE's policy focus to date has been on implementing nationally consistent energy markets consistent with the NER and competition policy reforms. A RNF (or any other scheme that might mitigate regional network pricing variations) would have effects contrary to this and could represent an internally inconsistent and hence difficult or impractical policy position for the MCE.

We suggest that an objective for the next step would be to garner initial support from both jurisdictional and Commonwealth governments both at the bureaucratic and political levels. However, the scheme as we have described would not necessarily require unanimous support of all jurisdictions. It could be implemented on an individual jurisdiction basis. Furthermore, it may be most cost effective to focus on Victoria, New South Wales and Queensland, on the basis that other states and territories are served by a single network or, in the case of Western Australia, has the Tariff Equalisation Fund in place. However, a campaign could promote the issue on a national context on the basis that it affects all regional businesses but is addressed to varying degrees by different jurisdictions (eg. the network structures of the ACT, Tasmania and South Australia provide intra network cross subsidies between regional and metropolitan customers).

Regional development or rural affairs departments such as Regional Development Victoria may offer the most promising route for the City of Greater Bendigo's advocacy. Again, this is because energy ministers within jurisdictions may be concerned with supporting an arrangement that may be inconsistent with national energy pricing arrangements they may have committed to via COAG. But, if the solution is addressed as being one of regional support rather than adjustments to energy pricing policy, this problem may be avoided. We also note that a final point implied by this is that the case for network support may be best made with regard to other advocacy for regional development support.

A Glossary and Acronyms

A.1 Glossary

Demand - The unit of electricity required. Demand is typically measured in kilowatts (kW) or megawatts (MW).

Load - The amount of electricity delivered or required over time. Load is typically measure in kilowatt hours (kWh) or megawatt hours (MWh).

Load profile - The variation in load over time.

A.2 Acronyms

ACCC	Australian Competition & Consumer Commission
AEMA	Australian Energy Markets Agreement
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
ESC	Essential Services Commission (Victoria)
ESCOSA	Essential Services Commission of South Australia
FRC	Full Retail Contestability
ICRC	Independent Competition and Regulatory Commission (ACT)
IPART	Independent Pricing and Regulatory Tribunal of NSW
MCE	Ministerial Council on Energy

B NEM Businesses

B.1 Transmission

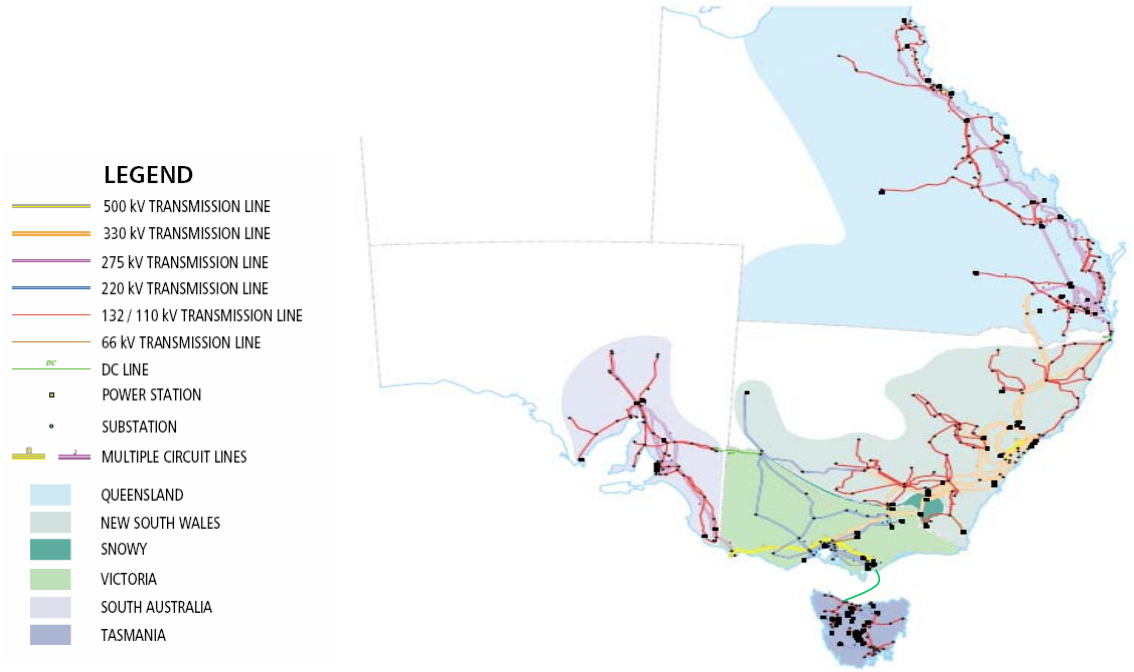
Transmission business	Transmission network(s)
TransGrid	NSW transmission network
	ACT transmission network
	Snowy Mountains Area transmission network
Powerlink	Queensland transmission network
	Queensland-NSW Interconnect (QNI) (this is jointly owned with Directlink)
SP AusNet and VENCorp	Victorian transmission network
	Victorian-NSW Interconnect
ElectraNet SA	South Australian transmission network
	SA-Victorian Interconnect
Transend Networks	Tasmanian transmission network
Directlink	Transmission interconnect between NSW and Queensland. It is a Market Network Service Provider.
Basslink	Transmission interconnect between Victoria and Tasmania. It is a Market Network Service Provider.
Murraylink	Transmission interconnect between Victoria and SA

B.2 Distribution businesses in the NEM

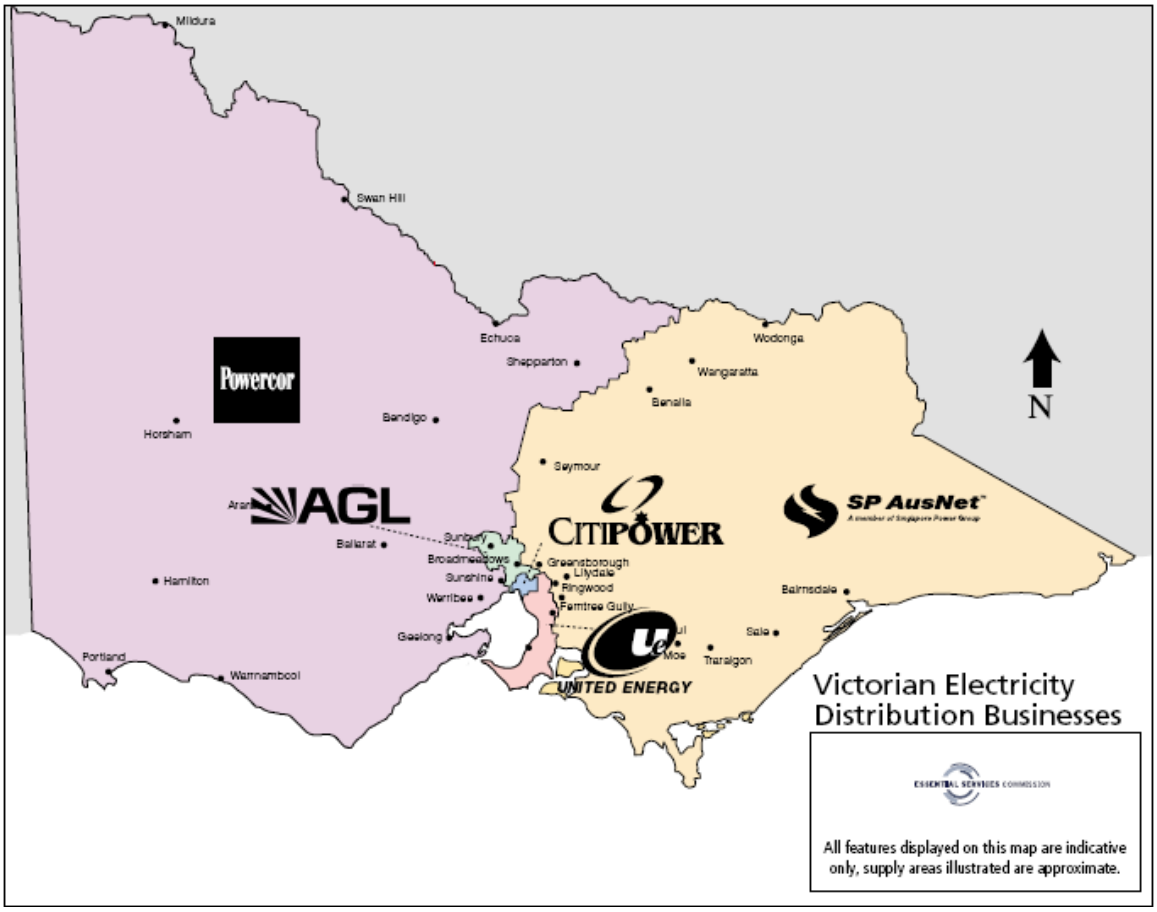
Jurisdiction	**Distribution business**
New South Wales	Country Energy
	Energy Australia
	Integral Energy
Queensland	Ergon
	Energex
Victoria	Powercor Australia
	Alinta
	United Energy Distribution
	SP AusNet
	CitiPower
South Australia	ETSA Utilities
Tasmania	Aurora Energy
ACT	ACTEW-AGL

C The NEM's electricity networks

C.1 NEM – Transmission Network

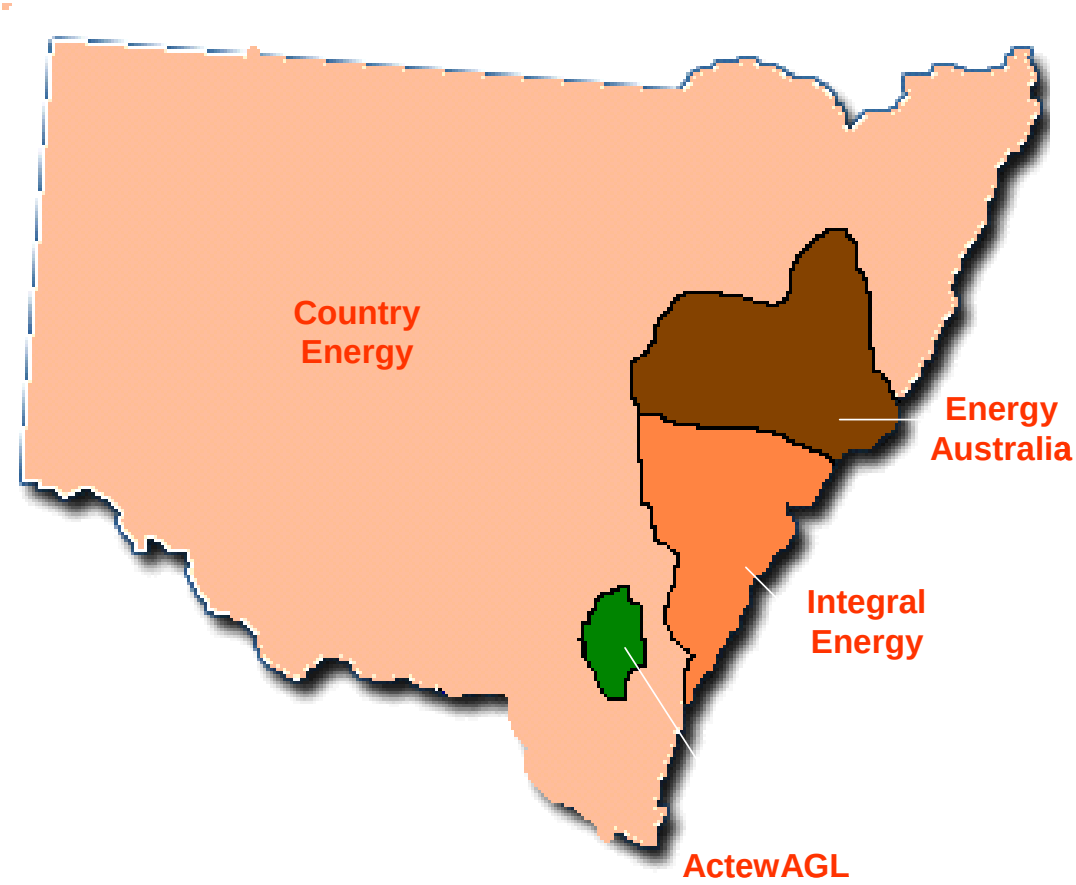


C.2 Victoria – Distribution Regions



Please note that subsequent to this diagram being drafted AGL's network is now owned and operated by Alinta.

C.3 NSW/ACT – Distribution Regions



C.4 Queensland – Distribution Regions

D Current arrangements to network pricing

This appendix outlines at a simplified level the 'building block' approach that Australian regulators commonly employ to assess network prices.

D.1.1 The building block approach

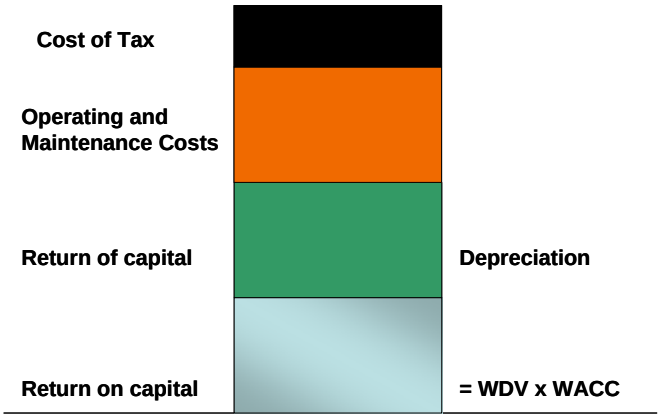
On the basis of submissions of forecasts from network businesses and independently sourced advice, regulators assess the efficient costs to provide the service and consequently the maximum allowable revenue for a transmission business or a maximum average price for a distribution business.

Regulators typically use the 'building block approach' to do this. This approach uses forecasts of costs of service provision and typically calculates total required revenue as the sum of:

- return on capital;
- return of capital;
- operating and maintenance expenditure; and
- cost of tax.

These are shown in the diagram below.

Figure D-1: Components of the building blocks



Return on capital compensates network businesses for the cost of capital invested in the network and bearing the risks associated with that investment. A return may also be provided in a forecast efficient working capital. The return is calculated by applying a benchmark efficient Weighted Average Cost of Capital ("WACC") expressed as a percentage to the written down value ("WDV") of the network and in some cases to an asset efficient level of working capital.

Regulators commonly apply a 'post-tax' WACC that does not include any *cost of tax* in the calculated return. Rather the cost of tax is assessed as a separate building block.

Return of capital is the amount of depreciation which is allocated across the life span of the asset.

Operating and maintenance costs are the forecast, efficient costs of operating and maintaining the asset to provide the 'prescribed' network.

Also where a business may have made an efficiency gain in a prior period by realising cost savings below the efficient targets set by the regulator, the business may be allowed to retain part of these savings in a subsequent five year regulatory period. This is to provide businesses with incentives to realise efficiency and pass through efficient costs to customers. Accordingly *efficiency gains* can form a further building block component.

The value of the network asset is vitally important to determining the total building block costs.

When networks are initially subject to economic regulation, the existing asset base is normally valued in Australia at:

- **D**epreciated
- **O**ptimal
- **R**eplacement
- **C**ost

("DORC")

rather than at historic cost.

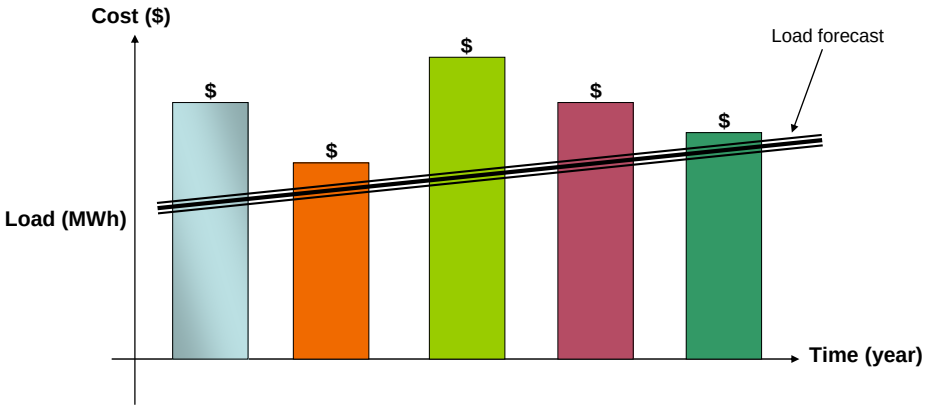
This is intended to ensure that customers do not bear the costs of past inefficient expenditure or sub-optimal or outmoded technology. Subsequent expenditure is normally rolled into the asset base at a regulatory allowed cost or actual cost, on the basis that the efficiency of that expenditure is subject to regulatory review.

The building blocks of forecast efficient costs for a regulated network are normally assessed for each year of a five year regulatory period.

D.1.2 How are distribution tariffs set?

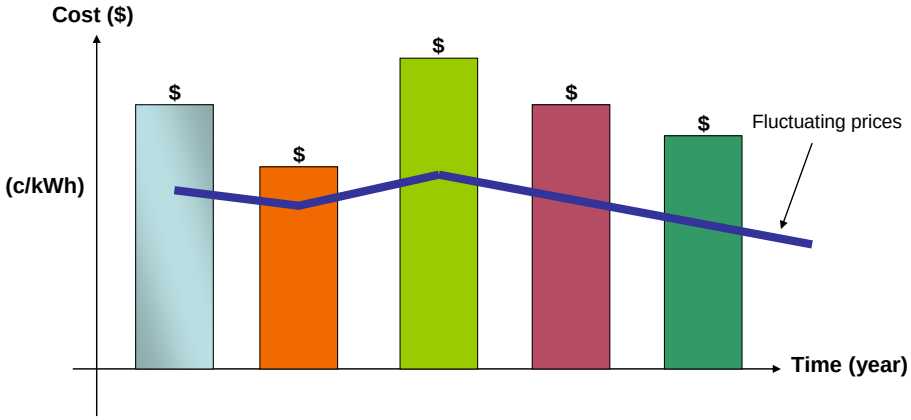
To help translate the required revenue into tariffs, network businesses also submit to the regulators forecasts of network load.

Figure D-2: Network load and efficient cost forecast



Note that while forecast load may change gradually, this may not be the case for total costs which could markedly change due to reasons such as a significant capital investment for a particular year. If prices were derived by simply dividing forecast cost by forecast load, this could lead to sudden changes in electricity prices from year to year as shown in Figure D-3.

Figure D-3: Fluctuating electricity prices (derived based on cost and load forecasts in D-2)



To avoid fluctuating average prices, prices are ‘smoothed’ over the regulatory period.

To do this, the net present value (NPV) of fluctuating prices throughout the regulatory period must equate to the NPV of the 'smoothed' prices. The maximum average prices are normally determined according to the following formula:

$$P_T = P_{T-1} \times \left[1 + (CPI - X)\right]$$

Such that

$$PV\left(P_T \times L_T\right) = PV\left(C_T\right)$$

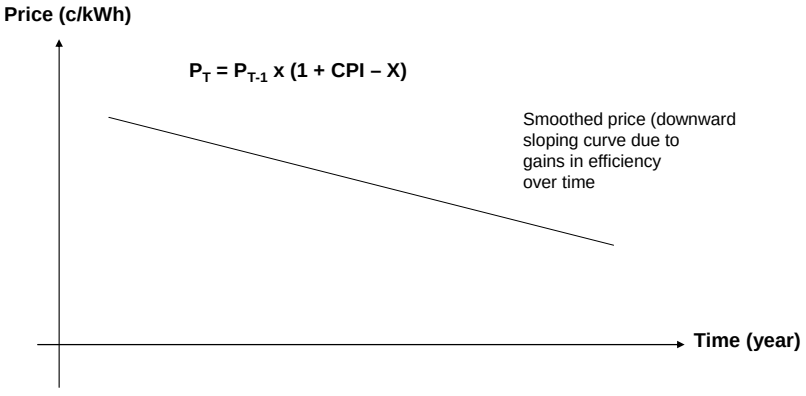
Where:

PV is the present value calculated over the five years of the regulatory period;
L_T is the forecast load for each year T;
C_T is the total building block cost for each year T.
P_T is the price in year T;
P_{T-1} is the price in year T-1;
CPI is the annual percentage change in the Consumer Price Index;
X is the real efficiency gain;

These equations are generally solved by fixing all variables except for X and solving for X.

This typically produces an average 'price path' for network charges such as that illustrated below.

Figure D-4: Consistent rate of change in tariffs



While X (the real reduction in prices due to efficiency gains) is a calculated outcome it arises from the efficient cost targets or forecasts incorporated by the regulator in the building blocks.

The regulator may include a sharper drop in prices in the first year by pre-determining $P_{T=1}$. Where this occurs the PV calculation operates to adjust X accordingly.

A sharp drop in the first year (often referred to as a 'P_0 adjustment') will result in lower subsequent real price reductions.

Figure D-4 above illustrates a maximum average price. Network businesses may structure individual tariffs such that they balance to that maximum average prices. This can be subject to complex 'price control' or balancing mechanisms where the regulator may also place constraints on the annual charges a network business may be permitted to apply including tariffs to balance to the maximum average price.

Distribution businesses are normally subject to a 'price cap'. That is to say, the prices rather than their revenue are regulated. This exposes the network business rather than its customers to the benefits and risks of changes in load from that forecast for price setting purposes, over the regulatory period, and provides the network with incentive to serve their markets and grow customer load.

D.1.3 How are transmission tariffs set?

Transmission businesses are generally subject to a revenue cap rather than a price cap. The formula is applied in a way which limits the total amount of revenue the businesses are allowed to receive and includes adjustments for under and over recoveries of prior years.

Structure of transmission tariffs

Transmission network owners split the charges borne by customers into the three components in accordance with the National Electricity Rules. These components are illustrated in Table D-1 below.

Table D-1: Components of transmission charges

Component of transmission change	Explanation
TUoS Usage Price	Locationally based demand charge which reflects long-run marginal cost of transmission at each point of connection to transmission network, e.g. • Yallourn and Wodonga approx. $4,000 to $6,000 per MW p.a. • Bendigo and Ballarat approx. $14,500 to $17,000 per MW p.a. • Horsham and Red Cliffs approx. $24,500 to $34,500 per MW p.a.[42]
Common Service Price	Non-locational costs including network planning and operations. There is a choice of energy price ($/kWh) or capacity price ($/kW) depending on jurisdiction. For example in Victoria the capacity price is only available where a customer's agreement nominates a fixed maximum demand and a substantial penalty for exceeding that demand.

[42] http://www.vencorp.com.au/docs/About_VENCorp/Electricity_TUOS_Prices_2006_07_Web_Document_Final.pdf

Component of transmission change	Explanation
TUoS General Price	Non-locational costs which recover the balance of revenue required. There is a choice of energy price ($/kWh) or capacity price ($/kW) depending on jurisdiction. For example in Victoria the capacity price is only available where a customer's agreement nominates a fixed maximum demand and a substantial penalty for exceeding that demand.

There may also be fixed annual charges intended to recover the costs of the assets required to connect the high voltage customer or distribution network to the transmission network.

While transmission tariffs include a locational element, they are not necessarily seen as being particularly cost reflective or effective at providing incentives for new investment in transmission and generation, in their present form.[43]

D.2 Setting network prices

D.2.1 Process of setting network tariffs

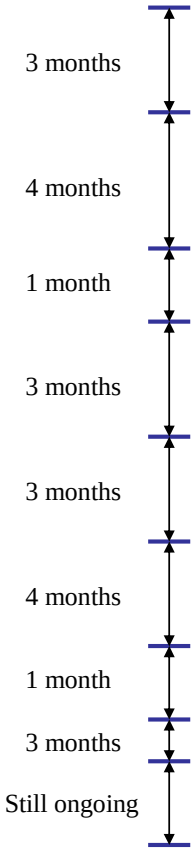
Section 3 describes how access to some segments of the electricity supply chain which are monopoly businesses, namely the transmission and distribution networks, are subject to regulatory oversight.

The process of setting network tariffs occurs periodically and involves public consultations. A network price review typically sets price controls that will apply to the network businesses for a period of five years. The process is consultative and can be lengthy. A timeframe of two to three years is not uncommon.

We present an example of the process in the following diagram. The timeline is based on Victoria's Electricity Distribution Price Review for calendar years 2006 to 2010.

[43] For example see the Parer Report Chapter 4.

Figure D-5: Example of distribution price review timetable



3 months	A **Consultation Paper** is published by the jurisdictional regulator to seek stakeholder comments on the proposed framework and approach to the price review process.
4 months	The **Final Framework and Approach** is agreed upon taking into careful consideration of stakeholders' submissions to the Consultation Paper. Information templates are prepared to gather relevant data from distribution businesses, and a guidance paper usually accompanies these templates.
1 month	Distribution businesses provide a **Summary of Price/Service Proposals** to the regulator, who then releases these for stakeholder comments.
3 months	An **Issues Paper** is published by the regulator to canvas the issues arising from the regulator's analysis of the Price/Service Proposals. The Issues Paper is also an invitation for further stakeholders' comments.
3 months	A **Position Paper** which outlines the regulator's preliminary views is published. Stakeholders may submit their comments at this point before the release of the Draft Decision.
4 months	The **Draft Decision** is published. It sets out the price control and revenue determinations for each distribution business. Again, stakeholders comments are welcomed at this stage of the process.
1 month	The **Final Decision** is published. It usually has a Statement of Purpose and Reasons; and the Price Determination.
3 months	Businesses may make an **Appeal** on matters of fact.
Still ongoing	The **Decision of the Appeal Panel** is released. Certain areas of the Final Decision may be revisited.
	The Final Decision is amended accordingly and finalised.

D.2.2 Entrepreneurial interconnects

Some interconnect transmission lines are not subject to regulated pricing. Rather they participate in the wholesale market advising on a source or purchaser of energy within each region of the NEM that they operate in. These networks accordingly make profits (or losses) according to their capacity to buy in one market region of the NEM (such as NSW) and sell the electricity so purchased within another market region of the NEM (such as Queensland).

E Quantitative data analysis

Qualitative and quantitative information was collected by KPMG to inform the project from a sample of 10 businesses across 27 locations in Victoria, New South Wales, Queensland and South Australia. The information was sought from participating businesses through two mechanisms:

- obtaining copies of a business' electricity bills for a number of different sites or locations and calculating load-weighted average charges (in cents per kWh) to compare network charges across locations (*quantitative data*); and
- conducting an interview (either face to face or via teleconference) to obtain qualitative information relating to the business' energy dependence, usage and costs, other relevant information relating to location choice, long-term impact of changes in electricity charges and size of operations (*qualitative data*).

This Appendix sets out:

- the basis of the sample selection;
- an analysis of the sample;
- the approach to compiling the analyses;
- the basis used to compare network costs; and
- the key findings from the quantitative analysis.

E.1 Data obtained

E.1.1 Criteria used to select sample

KPMG and the Project Steering Group identified the following selection criteria.

- **operating in multiple geographic locations** – to allow comparison of network charges across similar supply chains;
- **metropolitan and regional locations across the NEM** – to allow comparison of network charges across metropolitan and regional locations and across the NEM;
- **electricity-intensive or electricity dependent** – to include businesses for which electricity may be a material cost;
- **relocatable/"footloose"** – to include businesses that have a choice of where to locate their operations;

- **absence of energy substitutes (e.g. gas, diesel, LPG)** – to include businesses that are solely reliant on electricity for their principal energy source; and

- **operating in industries of critical importance to regional economies** – to include businesses that could negatively impact on the regional economy should they decide to relocate to another area.

KPMG and the Project Steering Group initially identified a sample of businesses that aligned with a number (but not necessarily all) of the selection criteria. Fifteen businesses were subsequently contacted by KPMG to participate in the Project.

A number of businesses contacted by KPMG were willing to participate in an interview, but were unwilling to provide billing information due to concerns of the information being commercial-in-confidence. Accordingly, the ten businesses included in the sample agreed to participate in an interview and provide billing information. However, as highlighted below, billing information was not ultimately received from all ten participating businesses.

E.1.2 Confidentiality

To protect participants' confidentiality, this report:

- does not disclose the names of participating businesses; and

- presents data and findings at an aggregated level.

E.1.3 Analysis of sample

KPMG requested each participant to provided copies (for each location) of the most recent 12 months of electricity bills from November 2005 to October 2006. The following tables outline the number of locations for which billing information was:

- requested from participating businesses;

- received from participating businesses (including those locations with less than 12 months of bills, incomplete copies of bills etc); and

- included in the analysis.

E.1.3.1 By State

Table E-1: Billing information requested, received and included in analysis (number of locations) – by State and Region

		NSW	Qld	SA	Vic	Total
Metro	Requested	1	3	2	6	12
	Received	1	2	2	6	11
	Included in analysis	1	2	1	6	10
Regional	Requested	3	3		13	19
	Received	3	3		11	17
	Included in analysis	3	3		11	17
Total	Requested	4	6	2	19	31
	Received	4	5	2	17	28
	Included in analysis	4	5	1	17	27

By "Metropolitan", we mean within the bounds of the capital city in each State. By "Regional", we mean all other locations.

Information requested for one business' location in Queensland and another business' two locations in Victoria were not received.

Information received from one location in South Australia was not sufficiently detailed for inclusion in the sample.

E.1.3.2 By industry sector as classified by the ASX

Table E-2: Billing information requested, received and included in analysis (number of locations) – by Industry and Region

		Consumer staples	Health	Industrials	Materials	Total
Metro	Requested	5	1	2	4	12
	Received	5	0	2	4	11
	Included in analysis	5	0	2	3	10
Regional	Requested	11	2	1	5	19
	Received	11	0	1	5	17
	Included in analysis	11	0	1	5	17
Total	Requested	16	3	3	9	31
	Received	16	0	3	9	28
	Included in analysis	16	0	3	8	27

The consumer staples sector:

- includes manufacturers and distributors of food, beverages and tobacco; producers of non-durable household goods and personal products; food and drug retailing companies; and hypermarkets and consumer super centres; and
- forms the majority of the sample.

However we have not further analysed participants' data for this sector by the next sub level (by industry group) because its particular composition was such that there could be a risk of data being identified with some individual participants.

E.1.3.3 Victoria - by industry sector and region

Table E-3: Victorian billing information requested, received and included in analysis (number of locations) – by Industry, State and Region

Victoria		Consumer staples	Health	Industrials	Materials	Total
Metro	Requested	3	-	1	2	6
	Received	3	-	1	2	6
	Included in analysis	3	-	1	2	6
Regional	Requested	6	2	1	4	13
	Received	6	0	1	4	11
	Included in analysis	6	0	1	4	11
Total	Requested	9	2	2	6	19
	Received	9	0	2	6	17
	Included in analysis	9	0	2	6	17

E.1.3.4 NSW - by industry sector and region

Table E-4: NSW billing information requested, received and included in analysis (number of locations) – by Industry, State and Region

NSW		Consumer staples	Materials	Total
Metro	Requested	-	1	1
	Received	-	1	1
	Included in analysis	-	1	1
Regional	Requested	2	1	3
	Received	2	1	3
	Included in analysis	2	1	3
Total	Requested	2	2	4
	Received	2	2	4
	Included in analysis	2	2	4

E.1.3.5 Queensland - by industry sector and region

Table E-5: Queensland billing information requested, received and included in analysis (number of locations) – by Industry, State and Region

Qld		Consumer staples	Health	Total
Metro	Requested	2	1	3
	Received	2	0	2
	Included in analysis	2	0	2
Regional	Requested	3	-	3
	Received	3	-	3
	Included in analysis	3	-	3
Total	Requested	5	1	6
	Received	5	0	5
	Included in analysis	5	0	5

Queensland billing information included in the analysis only comes from the Consumer Staples sector, covering both regional and metropolitan locations.

E.1.3.6 South Australia - by industry sector and region

Table E-6: SA billing information requested, received and included in analysis (number of locations) – by Industry, State and Region

SA		Industrials	Materials	Total
Metro	Requested	1	1	2
	Received	1	1	2
	Included in analysis	1	0	1
Regional	Requested	-	-	-
	Received	-	-	-
	Included in analysis	-	-	-
Total	Requested	1	1	2
	Received	1	1	2
	Included in analysis	1	0	1

E.1.4 By distribution area

Table E-7: Billing information included in analysis (number of locations) – by Distribution business

Distribution area	NSW			Qld		SA	Vic				
	Metro / Regional	Regional		Metro / Regional	Regional	Metro / Regional	Metro	Metro / Regional			
	Integral Energy	County Energy	Energy Australia	Energex	Ergon	ETSA Utilities	Citi-power	Alinta	Power-cor	SP AusNet	United Energy
Included in analysis	1	3	0	3	2	1	1	2	7	3	4

Billing information from all distribution areas in Queensland, South Australia, Victoria and NSW (except Energy Australia), was included in the analysis.

E.1.5 By annual consumption

Table E-8: Billing information requested, received and included in analysis (number of locations) – by consumption

Annual consumption	<1,000,000 kWh	1,000,000 - 5,000,000 kWh	5,000,000 - 10,000,000 kWh	>10,000,000 kWh
Example businesses	General small business, fast food restaurant, average school	Supermarket, small office block, large school	Multi storey office block, average hospital, small-medium manufacturing	Large hospital, large manufacturing facility
Included in analysis	3	14	3	7

E.2 Our approach

Filtering and data cleansing

Billing information was received in the form of copies of bills or electronic billing data (collated by the business or its retailer). The relevant information for each location was entered into an Excel worksheet and reviewed for consistency.

Dealing with incomplete time series of data to provide annualised figures

The billing data received was used to calculate a load-weighted average network charge in cents per kWh, which has been the unit of measure used to compare network charges across locations.

The analysis covers the period from November 2005 to October 2006, being the 12-months preceding the time of the data collection. However, a number of businesses did not provide a complete time series data for that period or provided bills that were incomplete.

There was a risk that the average cents per kWh (or 'average network charge') calculated to compare network charges across locations could be inaccurate if the missing data was significantly different (in terms of consumption profile and/or peak and off-peak consumption) to the historical data received. To compensate for this, KPMG applied the following approaches in preferred order, to estimate data necessary to calculate monthly network charges using the relevant network tariff.

- Where total monthly consumption was available, the split between peak and off-peak consumption was estimated using the:
  - graphical display of the split between peak and off-peak consumption for that month; or
  - average percentage split in historical data.
- Where total monthly consumption was not available, this was estimated using the:
  - historical average consumption (where data was not available for November 2005 only);
  - historical average consumption for the three preceding months' (where monthly consumption appears to be relatively consistent month-to-month);
  - graphical display of the average daily consumption for that month multiplied by the number of days in the month (where monthly consumption appears to vary month-to-month); or
  - business' average annual load profile (where majority of monthly bills are not provided and the individual participants' load profiles appeared to be relatively consistent across locations).

  The split between peak and off peak consumption was then estimated using the average percentage split based on historical data.

Data was defined and sorted as being 'actual' or 'estimated'. 'Actual' is defined as data obtained from a bill that provides complete information. 'Estimated' is defined as a bill where one or more component has been estimated by KPMG such as total consumption, peak consumption, off-peak consumption and/or network charges.

The following table outlines the number of actual and total bills (by State and Region) included in the analysis.

Table E-9: Number of actual and total bills included in analysis – by State and Region

State	Regional - Metro	Actual bills	Total bills
NSW	Metro	6	12
	Regional	48	48
Qld	Metro	13	24
	Regional	24	36
Vic	Metro	52	84
	Regional	94	132
SA	Metro	8	12
Total		245	348

It is important to note that for two locations, billing information for two electricity supply connections at that location has been included in the analysis.

Actual bills (with complete information on peak consumption, off-peak consumption and network charges) received by KPMG account for around 70 percent of total time series billing information included in the analysis.

The estimates described above provide a basis for extrapolating illustrative annualised total costs.

The risk of extrapolation error is likely be confined to the risks that the monthly loads and total network charges in the months for which bills were provided were not representative of the months for which bills were not available.

The impact of the extrapolations error on comparisons of cost on a cents per kWh basis described below may be more limited due to the approach undertaken to estimate the missing data as wherever possible the most accurate data was used.

E.3 Comparison of data - unit of measurement

Network charges may typically include standing charges and load and demand based charges. A load-weighted average charge in cents per kWh has been the unit of measure used to compare network charges across locations. This unit of measure has been utilised in preference to the other bases of charge or percentage of the total electricity bill or absolute network costs due to several factors:

- firstly, average cents per kWh is broadly accepted as an appropriate basis for the comparison of network tariffs. Standing and demand based charges tend to be less significant components of many network bills;

- comparing the percentage of total electricity bill attributable to network costs does not allow a reasonable basis for comparison as this can be impacted by the retail component of a customers bill that is determined by competitive market forces; and

- it normalises the charges for differences in total consumption and thereby provides a standardised basis of comparison for businesses of different sizes, load shapes and loss factors.

Whilst loss factors do vary by location and region they are not a separately itemised component within a customers network charges on their electricity bill. Rather they are included as one of many factors used within the determination of a network tariff that is ultimately approved by the relevant regulator. Accordingly, since loss factors are but one of many factors included within the determination of a network tariff it is not appropriate to analyse the impact of the differences in loss factors by region when determining a customers average network charges.

In addition, loss factors are typically incorporated as a component within the retail charges of a customer's bill. However as this component is not regulated and subject to market forces it is not appropriate to directly compare the impact of varying loss factors on customers' average retail charges.

E.4 Key findings

E.4.1 By State

The following table outlines the difference in average network charge between regional and metropolitan locations by State for businesses included in the sample. The estimates include the differences in average network charge based on actual billing information received, billing information estimated by KPMG (as described above) and total billing information (which includes both actual and estimated bills).

Table E-10: Estimated difference in average network charge between regional and metropolitan areas

State	Regional / Metro	Actual		Estimated		Total	
		# Bills	Average Network Charge (c/kWh)	# Bills	Average Network Charge (c/kWh)	# Bills	Average Network Charge (c/kWh)
Vic	Regional	94	3.33	38	3.01	132	3.26
	Metro	52	2.92	32	2.86	84	2.92
	Difference (c/kWh)		*0.41*				*0.34*
	Difference (%)		*14%*				*12%*
NSW	Regional	48	4.16	0	0.00	48	4.16
	Metro	6	3.78	6	3.78	12	3.78
	Difference (c/kWh)		*0.38*				*0.38*
	Difference (%)		*10%*				*10%*
Qld	Regional	24	2.73	12	2.31	36	2.67
	Metro	13	1.85	11	2.21	24	1.87
	Difference (c/kWh)		*0.89*				*0.79*
	Difference (%)		*48%*				*42%*
SA	Metro	8	5.38	4	4.79	12	5.18
Total			*10 - 48%*				*10 - 42 %*

The averages in this table are subject to bias in the sample. We note that care has to be taken in interpreting or referring to these numbers as there is a risk that the sample average differences illustrated above could reflect the impact of other factors on the limited sample sizes rather than purely regional and metropolitan differences.

It must be noted that these results for Queensland will (at least in part) be impacted by the specific tariffs included in the analysis, some of which have significantly larger annual standing charges than other businesses in the sample, and is therefore not directly comparable to other states.

Information from South Australia was only requested from a metropolitan location, so comparison across regional and metropolitan average network charges is not possible.

Moving locations

The following four tables summarise the estimated percentage differences in average network charges between one metropolitan or regional location and another metropolitan or regional location, based on the average network charges calculated for businesses in the sample in Table 5-1. We note that care has to be taken in interpreting or referring to these numbers as there is a risk that the sample average differences illustrated above could reflect the impact of other factors on the limited sample sizes rather than purely regional and metropolitan differences.

Table E-11: Estimated difference in network charges from regional to regional locations – by State and Region

		To Regional			
		Vic	NSW	Qld	SA
From Regional	Vic	-	28%	-18%	-
	NSW	-22%	-	-36%	-
	Qld	22%	56%	-	-
	SA	-	-	-	-

In terms of regional differentials in the sample, the largest differential in average network charge for businesses in the sample is between regional Queensland and regional NSW (56 percent), whereas the negative differential is between regional NSW to regional Queensland (-36 percent).

Table E-12: Estimated difference in network charges from regional to metropolitan – by State and Region

		To Metro			
		Vic	NSW	Qld	SA
From Regional	Vic	-11%	16%	-42%	59%
	NSW	-30%	-9%	-55%	24%
	Qld	9%	42%	-30%	94%
	SA	-	-	-	-

The largest positive differential in the sample was between regional Queensland and metropolitan South Australia (94 percent), whereas the largest negative differential is between regional NSW and metropolitan Queensland (-55 percent).

Table E-13: Estimated difference in network charges from metropolitan to regional– by State and Region

		To Regional			
		Vic	NSW	Qld	SA
From Metro	Vic	12%	43%	-9%	-
	NSW	-14%	10%	-29%	-
	Qld	74%	122%	42%	-
	SA	-37%	-20%	-48%	-

In terms of metropolitan differentials, the largest positive differential is between metropolitan Queensland and regional NSW (122 percent) and largest negative differential is between metropolitan South Australian and regional Queensland (-48 percent).

Table E-14: Estimated difference in network charges from metropolitan to metropolitan – by State and Region

		To Metro			
		Vic	NSW	Qld	SA
From Metro	Vic	-	30%	-36%	78%
	NSW	-23%	-	-50%	37%
	Qld	56%	102%	-	176%
	SA	-44%	-27%	-64%	-

Based on the sample, the largest positive differential in network charges for metropolitan businesses between Queensland to metropolitan South Australia (176 percent) and largest negative differential between metropolitan South Australia and metropolitan Queensland (-64 percent).

E.4.2 By distribution area

The structure of network tariffs can differ both across and within distribution areas. Table E-15 outlines average network charges for businesses in the sample by distribution area.

Table E-15: Average network charges – by State and Distribution business

State	Distribution business	Regional / Metro	Average Network Charge (c/kWh)
Vic	Alinta	Metro	3.34
	Citipower	Metro	2.53
	Powercor	Regional	3.29
	SP AusNet	Metro	3.18
	SP AusNet	Regional	4.08
	SP AusNet	*Combined*	*3.33*
	United Energy	Metro	2.55
	United Energy	Regional	1.89
	United Energy	*Combined*	*2.44*
NSW	Country Energy	Regional	4.16
	Integral Energy	Metro	3.78
Qld	Energex	Metro	1.87
	Energex	Regional	2.25
	Energex	*Combined*	*1.93*
	Ergon	Regional	2.74
SA	ETSA Utilities	Metro	5.18

All the businesses in the sample located in United Energy's distribution area are on the same network tariff. Accordingly, the differences in average network charge between metropolitan and regional businesses in this example appear to be a function of the businesses' consumption profiles. For example, one of the businesses located in United Energy's distribution area has a much lower average network charge than the other business due to its higher load factor.

In comparison, the businesses in the sample that are located in SP AusNet's distribution area are on different network tariffs. In this instance, the differences in average network charge between metropolitan and regional locations appear to be a function of both the tariff structure and the businesses' consumption profiles. For example, one of the regional businesses located in SP AusNet's distribution area has a higher average network charge due to its lower load factor and higher demand charge than the other regional business in SP AusNet's distribution area.

The businesses in the sample that are located in Energex's distribution area are on different network tariffs. Further, two of the three locations are on a network tariff where part or all components of the tariff are calculated on a site-specific basis, and therefore is not published in the public domain. In this instance, the difference in tariff structure is driving the differential in average network charge between metropolitan and regional locations. One business has a significantly higher standing charge than other businesses, but when divided by its high level of consumption results in a low average network charge (the lowest in the sample).

Within distribution areas the difference between average network charges between businesses included in the sample therefore appears be driven by the particular consumption profile

(primarily load factor) and network tariff for businesses, rather than due to their location being metropolitan or regional only.

Network tariffs within a distribution area do not normally differentiate between customers located in 'metropolitan' areas and those located in 'regional' areas. For example, Powercor and SP AusNet in Victoria have customers located across both metropolitan and regional areas.

E.4.3 By industry sector

The following table is similar to Table E-10, but separates out the difference in average network charge between regional and metropolitan locations by State and industry sector.

Table E-16: Estimated impact on annual network charges – by Industry, State and Region

State	Sector	Regional / Metro	Actual		Estimated		Total	
			# Bills	Average Network Charge (c/kWh)	# Bills	Average Network Charge (c/kWh)	# Bills	Average Network Charge (c/kWh)
Vic	Consumer	Regional	26	2.80	34	2.92	60	2.83
	Staples	Metro	26	2.51	22	2.64	48	2.54
		Difference (c/kWh)		*0.30*				*0.29*
		Difference (%)		*12%*				*12%*
	Industrials	Regional	12	4.19			12	4.19
		Metro	9	3.24	3		12	3.19
		Difference (c/kWh)		*0.95*				*1.00*
		Difference (%)		*29%*				*31%*
	Materials	Regional	56	4.27	4	3.28	60	4.08
		Metro	17	3.21	7	5.04	24	3.25
		Difference (c/kWh)		*1.06*				*0.83*
		Difference (%)		*33%*				*25%*
NSW	Consumer	Regional	36	4.11			36	4.11
	Staples	Metro		-				-
		Difference (c/kWh)		-				-
		Difference (%)		-				-
	Materials	Regional	12	4.36	0		12	4.36
		Metro	6	3.78	6	3.78	12	3.78
		Difference (c/kWh)		*0.57*				*0.58*
		Difference (%)		*15%*				*15%*
Qld	Consumer	Regional	24	2.73	12	2.31	36	2.67
	Staples	Metro	13	1.85	11	2.21	24	1.87
		Difference (c/kWh)		*0.89*				*0.79*
		Difference (%)		*48%*				*42%*
SA	Industrials	Metro	8	5.38	4	4.79	12	5.18

In terms of total billing information included in the analysis, Queensland businesses in the Consumer Staples sector have the lowest average network charges in the sample (for both regional and metropolitan businesses).

For the Victorian businesses included in the sample, those businesses in the Consumer Staples sector have significantly lower average network charges in both regional and metropolitan locations than those businesses in the Industrials and Materials sectors.

E.5 Illustrative examples

The following outlines the assumptions used in the calculations for the illustrative examples in section 5.1.3.

E.5.1 General assumptions

Consumption

The base cases use the actual monthly peak and off peak consumption data from November 2005 to October 2006 for two businesses in the sample located in regional Victoria. This includes one low voltage customer with annual consumption around 1,400,000 KWh and a high voltage customer with annual consumption around 9,000,000 KWh.

Annual network charges have been calculated using the base case actual monthly peak consumption, off peak consumption and maximum demand data, and applying a comparable tariff for the particular business type in each location (see description of the tariffs included below).

Peak demand and power factor

The base case (a business in the sample located in regional Victoria) has peak demand measured in terms of kW. The network owners in the jurisdictions of NSW and SA however, measure peak demand in kVA. To determine the total network charges for a business located in either of these regions, we have made an assumption about the equivalent peak demand in kW to enable meaningful comparison against the base case.

The conversion of peak demand from kVA to kW involves a power factor. This is the ratio of *real power* to *apparent power*, which measures how effectively current is converted to useful output. The power factor lies between 0 and 1, with 1 being most efficient.

For the purposes of the case study, we have assumed the business to have a power factor of 0.90. Thus, a peak demand of 150kW is equivalent to 167kVA. This estimate is based on the minimum power factor limit of 0.85 for customer maximum demand between 100 kVA and 2 MVA with supply voltage between 6.6 kV and 22 kV outlined in the ESC Victoria Electricity Distribution Code January 2006. The Code states that customers must keep the power factor of its electrical installation above the minimum level when demand is at or more than 50 percent of the customer's maximum demand. It is therefore reasonable to assume that the average business customer would have a power factor greater than the minimum level of 0.85 to ensure compliance with the Code. Further there is an incentive (especially for large businesses) to implement correction mechanisms since poor power factors increases energy demand and consequently, total energy charges.

For the purposes of the case study, we have also assumed that both the low voltage and high voltage customer operate on a consistent basis seven days per week, and therefore peak maximum demand is around the same level as off-peak demand.

E.5.2 Tariffs used in the analysis for Low Voltage business case study

Please note that the most recent applicable tariffs have been utilised. Victoria has calendar year tariffs, whereas NSW, Queensland and South Australia have financial year tariffs.

Victoria regional – Powercor Large Low Voltage Demand (DL) – Available to large customers, with demand greater than 250 kW and supply voltage less than 1,000V. Prices effective 1 January 2006 – 21 December 2006.

Victoria metropolitan – Citipower Large Low Voltage Demand (C2DL) - Available to large customers, with demand greater than 120 kW and supply voltage less than 1,000V. Prices effective 1 January 2006 – 21 December 2006.

NSW regional – Country Energy BLND3A0 LV ToU Demand – Applicable to business premises whose consumption exceeds 100 MWh per annum and connected to the LV distribution system in locations across Country Energy's distribution area (excluding Far West Region). Prices effective 1 July 2006 – 30 June 2007.

NSW metropolitan – Integral Energy LV Demand ToU - Demand ToU prices apply to each supply point consuming 160 MWh per annum and over. Prices effective 1 July 2006 – 30 June 2007.

Queensland regional – Ergon Large Demand DUoS (EDL) and TUoS for Rockhampton - East Zone pricing (connected to National Grid). Standard Asset Customers with consumption greater than 100MWh per annum. Rockhampton is a regional city with industry and is a location within the sample. Rockhampton is one of 41 transmissions connection points in Ergon's distribution area. Prices effective 1 July 2006 – 30 June 2007.

Queensland metropolitan – Energex Large Demand (DL) - Standard Asset Customers with consumption less than 4 GWh per annum. For customers with minimum chargeable demand of 400 kW. Prices effective 1 July 2006 – 30 June 2007.

South Australia – ETSA Utilities Low Voltage Stepped Demand (VLVS) – For low voltage customers with minimum chargeable demand of 100 KVA. Prices effective 1 July 2006 – 30 June 2007.

E.5.3 Tariffs used in the analysis for High Voltage business case study

Victoria regional – Powercor High Voltage Demand (DH) – Available to large customers, with demand greater than 1,000 kW and supply voltage greater than 1,000V and less than 22,000V. Prices effective 1 January 2006 – 21 December 2006.

Victoria metropolitan – Citipower High Voltage Demand (C2DH) - Available to large customers, with demand greater than 1,000 kW and supply voltage greater than 1,000V and less than 22,000V. Prices effective 1 January 2006 – 21 December 2006.

NSW regional – Country Energy BHND3A0 HV ToU Demand – Applicable to business premises whose consumption is connected to the HV distribution system in locations across Country Energy's distribution area (excluding Far West Region). Prices effective 1 July 2006 – 30 June 2007.

NSW metropolitan – Integral Energy LV Demand ToU - Demand ToU prices apply to each supply point consuming 160 MWh per annum and over. Prices effective 1 July 2006 – 30 June 2007.

Queensland regional – Ergon High Voltage DUoS (EDH) and TUoS for Rockhampton - East Zone pricing (connected to National Grid). Standard Asset Customers with consumption greater than 100MWh per annum. Rockhampton is a regional city with industry and is a location within the sample. Rockhampton is one of 41 transmissions connection points in Ergon's distribution area. Prices effective 1 July 2006 – 30 June 2007.

Queensland metropolitan – Energex High Voltage (DL) - Standard Asset Customers with consumption less than 4 GWh per annum. For customers with minimum chargeable demand of 400 kW. Prices effective 1 July 2006 – 30 June 2007. Note: given that consumption is greater than 4GWh per annum, the tariff should be a 'Connection Asset Customer' tariff. However, 'Connection Asset Customers' have fixed charges are site-specific which can vary significantly, making assumptions on the scale of the fixed charge problematic.

South Australia - ETSA Utilities High Voltage Stepped Demand (VHVS) – For high voltage customers with minimum chargeable demand of 100 KVA. Prices effective 1 July 2006 – 30 June 2007.

F Qualitative data analysis

F.1 Data obtained

KPMG conducted in-person and telephone interviews with ten businesses, whose business operations included locations in Victoria, New South Wales, Queensland and South Australia.

The interview questions sought to obtain qualitative information from participating businesses relating to their energy dependence, usage and costs, along with other relevant information relating to location choice, long-term impact of changes in electricity charges and size of operations.

F.1.1 Interview questions

Participating businesses were asked the following questions in the interview.

Business background information

1 Please provide some background to your business in each location? For example, brief history, number of people you employ in each location, indicative annual turnover etc.

2 What are the key location-specific / regional influences over your operations at each location, and what are the implications for your choice of business location? For example:

- access to:
    - suppliers/raw materials;
    - customers;
    - labour;
    - energy; and
    - transport infrastructure;
- operational and capital investment costs?

Electricity supply – reliability and quality

3 How important is the reliability of electricity supply to you at your different locations? ("Reliability" refers to the duration and frequency of interruptions to electricity supply).

4 How important is the quality of electricity supply to you at your different locations? ("Quality" refers to short term or transient voltage increases or decreases, or changes in alternating current frequency (or harmonic distortion)).

5 To what extent are reliability and quality of electricity supply important influences on determining where to locate your businesses' operations?

6 Which is more important to your business:

- Marginal reductions in price of electricity supply; or
- Marginal improvements in quality and reliability of supply

How does the answer to this question vary according to location?

Energy supply - costs

7 How significant have electricity costs been to your business over the past 24 months?

8 How significant are electricity costs to your business likely to be into the future?

9 Are you aware of these three components within your total electricity charges:

- retail usage charge;
- distribution and transmission network charges; and
- other Charges, including metering and market fee charges.

10 Are you aware of the various network charges (tariffs) that might apply to you?

11 How aware are you of differences in electricity network charges between metropolitan and regional areas?

12 If you have locations in Victoria: Are you aware of Victoria's Transmission Equalisation Scheme and its unwinding? If so, how will this impact on your business?

Energy supply - choices

13 Which alternative sources of energy (e.g. gas, diesel, LPG) are reasonably available for your business at each of your locations?

14 If practical alternatives are available, what influenced your choice of electricity?

15 If practical alternatives are *not* currently available, would you consider an alternative to electricity if one were to become available? What would influence this consideration?

16 To what extent would access to alternative energy sources be an important influence on future business location decisions?

17 Have you considered co-generation as an alternative or supplement to supply from the grid? If so, what factors were important to your business, in considering this option.

F.2 Key findings

The following provides the key findings from the interviews conducted with the ten businesses.

Note the responses to the questions posed to businesses have been grouped according to the headings included in the list of questions above.

F.2.1 Business background information (Questions 1 – 2)

Of the ten businesses interviewed, there were a number of key influences on their choice of business location. A few businesses listed more than one key influence on their choice of business location, with the majority of business operating in their current locations due to one key reason. Accordingly, some businesses could be included in multiple categories, therefore the percentages do not total to 100 percent.

Tradition or historic business location was a significant influence on business location for 50 percent of businesses interviewed, with a number of businesses first established in some locations around 50 and to 100 years ago.

Access to customers was of critical importance to 30 percent of businesses interviewed, with two businesses commenting they have specifically located some recently established operations close to their key customers. Access to suppliers and raw materials was a key consideration for two businesses (20 percent).

A number of businesses (40 percent) commented that electricity costs are not a key consideration when deciding where to locate their operations. Only one business responded that when choosing a new location for their operations they attempt to choose a location with good access to a substation, but acknowledged that electricity costs are not considered by management as much as they should. Heightened awareness of the locational differential in network costs could therefore change this view.

Overall, it appears that electricity is not a key consideration for the businesses interviewed when deciding where to locate their operations.

F.2.2 Electricity supply - reliability and quality (Questions 3 – 6)

Both reliability and quality of electricity supply was important to business in the sample.

Reliability of electricity supply (where "reliability" refers to the duration and frequency of interruptions to electricity supply) was rated as "very important" to 80 percent of businesses interviewed, and "important" to 20 percent.

Some businesses (40 percent) had backup generators to ensure continuous electricity supply. The need for backup generation was due to the nature of their business requiring continuous electricity and to insure against the risk of disruption to their 24 hour / 7 day operations.

Over half of businesses (60 percent) commented that they were generally happy with their current level of reliability of electricity supply (with the remaining businesses not commenting on their satisfaction with current reliability of supply).

Quality of electricity supply (where "quality" refers to short term or transient voltage increases or decreases, or changes in alternating current frequency (or harmonic distortion)) was rated as "very important" to 50 percent of businesses interviewed, "important" to 30 percent and "not important" to two businesses (20 percent).

Power protection equipment had been installed by 40 percent of business interviewed, with two businesses (20 percent) monitoring the quality of their electricity supply. Just under half of businesses (40 percent) commented that they were generally happy with their current level of quality of electricity supply (with the remaining businesses not commenting on their satisfaction with current quality of supply).

The majority of businesses interviewed (80 percent) responded that reliability and quality of electricity supply were "not important" influences on determining where to locate their business' operations, with only 20 percent rating reliability and quality of electricity supply as "important" influences on business location.

The sample was divided in terms of preference for reduced electricity prices versus improvements in quality and reliability. Seventy percent of businesses interviewed outlined a preference for marginal reductions in price of electricity supply in favour of marginal improvements in quality and reliability of supply, on the assumption that current levels of quality and reliability of supply is maintained. In comparison, 30 percent of businesses would prefer marginal improvements in their quality and reliability of supply in favour of marginal reductions in price, with one business responding that they would be willing to pay more for better quality and reliability.

F.2.3 Energy supply - costs

F.2.3.1 Significance of electricity supply costs (Questions 7 – 8)

Electricity costs were important to all businesses in the sample. Electricity costs were rated by 60 percent of businesses interviewed as being "significant" over the past 24 months and 30 percent rating electricity costs are "moderately significant". Only one business (10 percent) rated electricity costs as "very significant".

Two businesses believed that their electricity costs were likely to become "very significant" components of their costs into the future (in comparison to currently being rated as "significant"), due to anticipated increases in contracted (retail) prices. Businesses are therefore more likely to focus on total electricity costs rather than on network costs specifically.

F.2.3.2 Awareness of electricity charges (Questions 9 – 12)

There was general level of awareness amongst businesses interviewed of the components within total electricity charges; various tariffs that might apply to their business; and the regional / metropolitan differences in electricity network charges.

- 90 percent of businesses interviewed were aware of the three components within total electricity charges, namely retail usage charge; distribution and transmission network charges; and other charges, including metering and market fee charges.

- 90 percent of businesses interviewed were aware of the various network charges (tariffs) that might apply to their business.

- 70 percent of businesses interviewed were aware of the differences in electricity network charges between metropolitan and regional areas, with two businesses (20%) only aware due to their involvement in the previous study undertaken through the City of Greater Bendigo.

However, there was a low level of awareness of Victoria's Transmission Equalisation Scheme and its unwinding amongst Victorian businesses interviewed. Of the nine businesses with operations in Victoria, only 22 percent of businesses interviewed were aware of Victoria's Transmission Equalisation Scheme and its unwinding. This implies that the TEA is a hidden subsidy

F.2.4 Electricity supply – choices (Questions 13 – 17)

The following alternative sources of energy are reasonably available and utilised by businesses at their locations:

- Gas (90 percent);

- Coal (20 percent);

- Diesel (20 percent);

- LPG (10 percent); and

- Co-generation (10 percent).

Access to alternative energy sources was "not important" in influencing future business location decisions for those interviewed, with 90 percent rating access to alternative energy sources as "not important". The key influence for these businesses choosing electricity was that equipment utilises electricity, and either cannot use other sources of energy or cannot cheaply be converted to utilise other sources of energy.

Sixty percent of businesses interviewed had considered co-generation as an alternative or supplement to supply from the grid, with 30 percent responding that it was not a viable option for their business.

The businesses in the sample are therefore dependent on electricity as a source of energy and have no effective choice of alternative energy sources, despite reasonable access to alternatives.