Western Power: Network cost analysis & efficiency indicators

Volume I
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Benchmark Economics

Tel 61 2 9428 2079
Mobile 0438 603 701
Email: mbeardow@bigpond.net.au

Table of Contents

1 Introduction

The Western Australian Economic Regulation Authority (ERA) in accordance with its responsibilities under the Electricity Networks Access Code is undertaking a review to determine appropriate revenue controls for the transmission and distribution networks of Western Power. The review will set allowed revenues for the period 2006–2009.

As part of its pricing determination, the ERA is required to calculate capital and non-capital related expenditures. These expenditures must measure forward-looking and efficient costs which would be incurred by a prudent service provider without reducing service quality below the standards set for each covered service in the access arrangement.

Benchmark Economics has been engaged by Western Power to assist with its submission to the ERA by providing an expert view on certain aspects of its forward looking expenditures. These include:

- identifying major transmission and distribution network cost drivers;
- analysing the influence of the identified cost drivers on Western Power's transmission and distribution network;
- providing a comparative assessment of the cost performance of Western Power relative to its peers. This includes total costs, operating an maintenance expenditures and capital expenditures; and
- providing an estimate of total costs appropriate to Western Power's network configuration and prudent operating and maintenance and capital expenditure.

To identify the network cost drivers and their influence on Western Power's relative cost performance the analysis in this report has been guided by the electricity network cost model developed by Benchmark Economics. Though this model was developed primarily for the analysis of distribution networks, the principles established are equally appropriate to the high voltage transmission grid. Use of a theoretically structured model allows robust identification of major cost drivers and, therefore, more accurate estimation of expenditure benchmarks. To be credible, expenditure benchmarks must be appropriate to Western Power's operating environment and comparable to its peers.

The cost structure analysis is presented in two volumes. The first, *"Western Power: Network cost analysis & efficiency indicators"* presents the cost analysis and proposes appropriate expenditure indicators. The second, Volume II, details the theoretical framework for the distribution cost model used in the first report.

This Volume is structured as follows: The report first presents a discussion of issues relevant to both transmission and distribution networks. It includes the measurement of network performance, economics guidance on network costs, the distinction between cost and price, and the emerging investment requirement to replace aging infrastructure. The next section reviews the distribution network. It first considers the current cost performance for the distribution network of Western Power, identifying cost drivers and reviewing current operating and capital expenditures for Western Power. The second part provides an assessment of the expenditure allowances proposed for by Western Power for the period 2005-06 to 2009-10. Drawing on the links established by the network cost structure model the expenditure proposals are assessed relative to comparable networks. Appropriate cost indicators are identified for these expenditure categories.

Transmission network cost structures are considered in the final section. Current cost performance is first addressed before the analysis turns to an assessment of the expenditure proposals for the period 2005-2010. Finally, cost indicators appropriate to the transmission network are identified.

2 Measuring network performance

Despite the trend among international regulators to adopt incentive-based pricing, with its inherent requirement for "efficient cost" benchmarking, there is no standard model for analysing network cost performance. Without an integrated framework to quantitatively link outputs produced to input costs incurred the selection of performance indicators has often been ad hoc. It is not surprising that efficiency targets imposed on network businesses have been subject to dispute.

Benchmarks based on partial productivity measures are especially prone to misinterpretation since by definition they will measure only one aspect of network performance. There is little opportunity to account for business conditions. Nevertheless, it is recognised that regulators will have recourse to partial measures in the absence of more integrated econometrically derived cost models.

Work on one such model has been underway in Australia over the past few years. The first stage has now been completed. This provides a framework for an integrated cost model that is soundly based in both economic and engineering theory. Cost drivers have been identified and their impact on distribution network costs quantified. The following analysis for Western Power is based on this cost model framework.

The second stage, full integration of the partial econometric parameters is some way off. The small number of Australian network businesses precludes robust integration of these parameters. Several attempts have been made to incorporate overseas networks into the analysis to provide a larger sample but this has not proved successful due to the considerable difference between network conditions and accounting cost allocations.

2.1 An economic guide to network cost structures

A major problem confronting network cost analysis has been the correct identification of key cost drivers. This should not be so since economics offers useful guidance for analysing network cost performance. The theory of the cost of production describes the way in which firms transform purchased inputs (the factors of production) into outputs. Network **outputs**, therefore, are those products or services resourced from paid **inputs**. In some way the outputs of electricity distribution networks represent the transformation in the production process of poles, wires, transformers, and system controls.

Accordingly, electricity distribution businesses are held to transform capital and other inputs into the following outputs:

- *Connectivity* – extent of network from bulk supply points to end-users. It represents the inputs of poles and wires and is specified in the cost model as line length km. For transmission it is the extent of the network from the grid exit point to the bulk supply point;
- *Capacity* – the capability the network to satisfy the demand of end-users. It represents the inputs of transformers and substations and is specified in the cost model as coincident peak demand measured in MW;
- *Connections* – end-users connected to the network. It represents contribution of connection equipment eg poles and meters, and end-user related services and is specified in the cost model as number of end-users connected to the network. For transmission, the number of generators connected replaces the number of end-users; and
- *Reliability* – availability and continuity of energy delivery to end-users. It represents the contribution of inputs such as equipment redundancy, multiple circuits, and operating and maintenance practices and is specified in the cost model as SAIDI or minutes off supply for transmission.

Operating within diverse demographic and geographic conditions, certain aspects of the operating environment will also have a significant influence on relative costs. Following quantitative assessment of a large range of possible factors, two major conditions have been identified:

- *Connection density*: measured as the number of connections or capacity provided per km line length; and
- *Customer class*: measured as the average level of energy consumption for end-users. A variation of consumption levels, load factor, is measured as the ratio of average demand to peak demand.

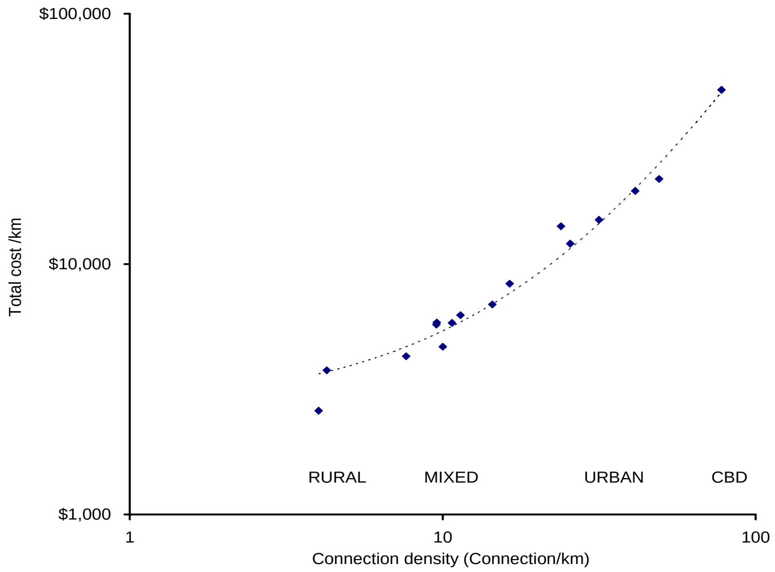
The relation between these cost drivers and total costs for the distribution networks is exhibited in Figures 1 and 2. To avoid unnecessary complexity, the discussion on transmission is hold over to the second section.

The powerful influence of connection density effectively separates Australia's networks into four groups for purposes of cost comparisons: CBD, urban, mixed (mainly state-wide networks – Western Power is in this group), and rural (Figure 1). The trend line in Figure 1 has an R^2 of 98 per cent. This result is not simply a characteristic of the Australian system. Similar analysis for the more numerous and diverse New Zealand networks[1]

[1] A number of New Zealand networks are not for profit municipal based systems. Consequently there is less uniformity in the structure of network costs than in Australia where each network cost stream includes a return on capital, depreciation and opex.

reveals an R^2 of 93 per cent. Given the strength of fit, it is surprising that the impact of density has not been more widely taken to account in cost comparisons.

Figure 1: Connection density: Total cost/km and connections/km

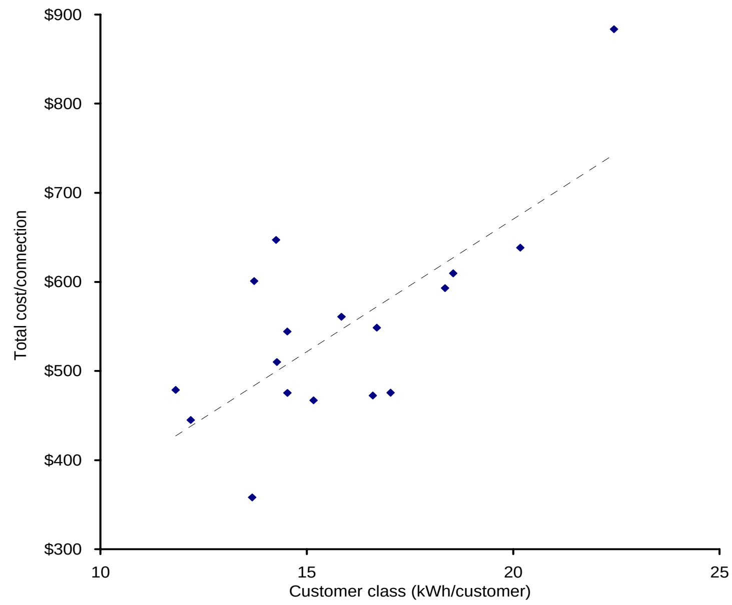


Customer class reveals greater diversity although the link between rising average consumption and rising connection costs is still evident. Importantly for performance comparisons, networks with the largest end-users, typically industrial or mining customers, tend to be situated in rural areas with low connection density.

Measured against one performance indicator a network may exhibit the highest level of costs yet measured against the other it could exhibit the lowest costs. There is little in the empirical literature to guide the regulator on the selection of the most appropriate measure. Judgments about the most appropriate measure of "efficiency" can only be arbitrary.

Despite the presence of the basic economic concept linking industry outputs to the transformation of inputs, correctly identifying the network product remains a major challenge. Consequently, some partial indicators used regularly in performance comparisons may be inappropriate or simply incorrect.

Figure 2: Customer class: Total cost/connection and kWh/connection



2.1.1 Distinguishing between cost and price

The most prominent indicator used incorrectly is the ratio of total costs to energy throughput: $/MWh. It is widely accepted practice in performance analysis to compare network costs by using *energy* flows (MWh) as an output. Accordingly, the ratio revenue/MWh has become one of the most frequently used cost performance indicators.

This is not correct. Energy is not an output of electricity networks since it is not derived from the transformation of poles and wires; it represents only the transformation of coal or gas in generator units. The measure $/MWh simply measures the **price charged for the use of** the system, an interpretation which is reinforced by the term "distribution *use of system* charge. This distinction is analogous to the cost of constructing a road and the price (toll) charged for its use.

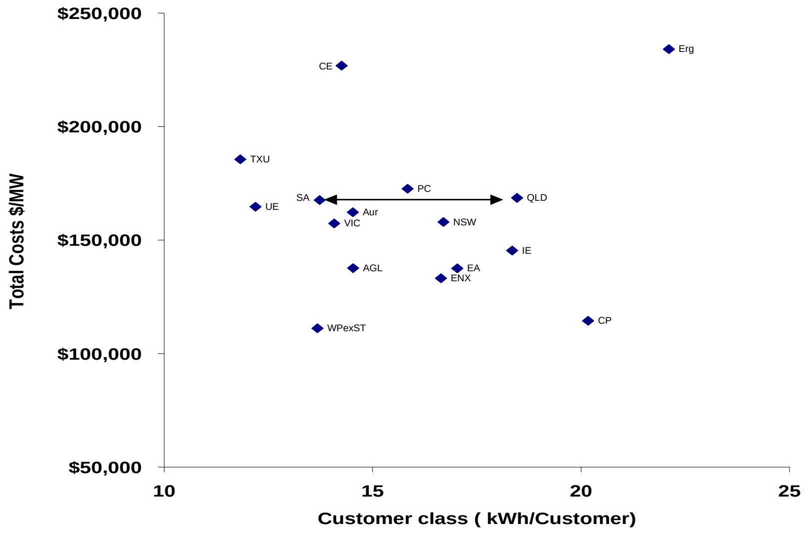
In regulated pricing, the **cost** of a network is defined as the sum of the building blocks. That is, the rate of return on, and of, capital plus operating and maintenance expenditure. In turn, these "blocks" are determined by the level of investment in the network necessary to accommodate the demands of end-users. Once the investment is made, its **cost** is recouped, over time, by charging a fee for its *use.* For any given cost, increasing the use of the network (quantity of energy conveyed along the wires) will lower the unit price, that is building block revenue/energy flow or $/MWh.

Consequently, while networks may well have comparable costs ($/MW), those with higher energy flows relative to the network capacity provided (the ratio of energy to capacity is defined as load factor), will exhibit lower **prices**, $/MWh, since they are able to spread their high fixed costs across a greater number of units "sold". This principle is equally applicable to the transmission and distribution networks.

Figures 3 and 4 illustrate this point. Figure 3 plots average costs, measured as $/MW, against customer class, (kWh/connection) while Figure 4 plots average price, measured as $/kWh, also against customer class. The change in position of the South Australian network provides a striking example of the influence of energy flows on comparative prices.

Considering first its cost position, in Figure 3 we observe that South Australia's costs are equivalent to those of the Queensland network, around $168,000/MW. However, Figure 4, depicting price, reveals a significantly different outcome. South Australia now has a price level substantially above that of Queensland, $43/MWh compared to only $33/MWh. The sharp difference between South Australia's position between Figure 3 *Costs* and Figure 4 *Prices*, is driven mainly by its load factor. With a relatively low industrial base and

Figure 3: Costs and customer class



and high residential summer air-conditioning load it has a load factor of only 49 per cent, one of the lowest in Australia and comparable to that of Western Power.

In contrast, Queensland with a strong industrial and mining load has a load factor 20 per cent higher at 60 per cent. Effectively, South Australia transports only 4292 MWh each year out of a possible 8760 MWh for each MW of capacity installed compared to 5256 MWh transported in Queensland.

Figure 4: Prices and customer class

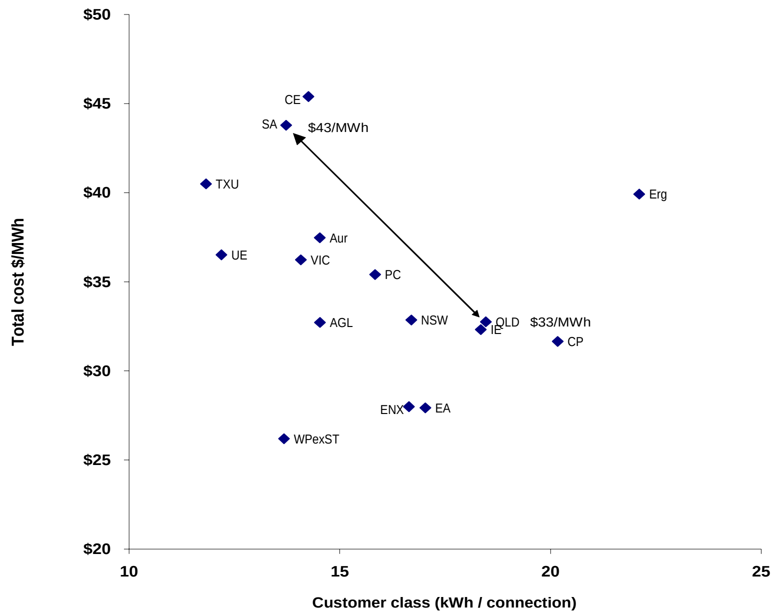


Table 1 provides the simple calculations:

Table 1: Load factor and network prices

	Load factor	Energy MWh	Cost per MW	Price per MWh
South Australia	45%	3942	$168,000	$168,000 / 3942 = $43
Queensland	57%	4950	$167,000	$167,000 / 4950 + $33

Performance comparisons that mistakenly use the price indicator, $/MWh, to measure cost will disadvantage Western Power and other networks with poor load factors. This factor is also relevant when comparing transmission or generation costs.

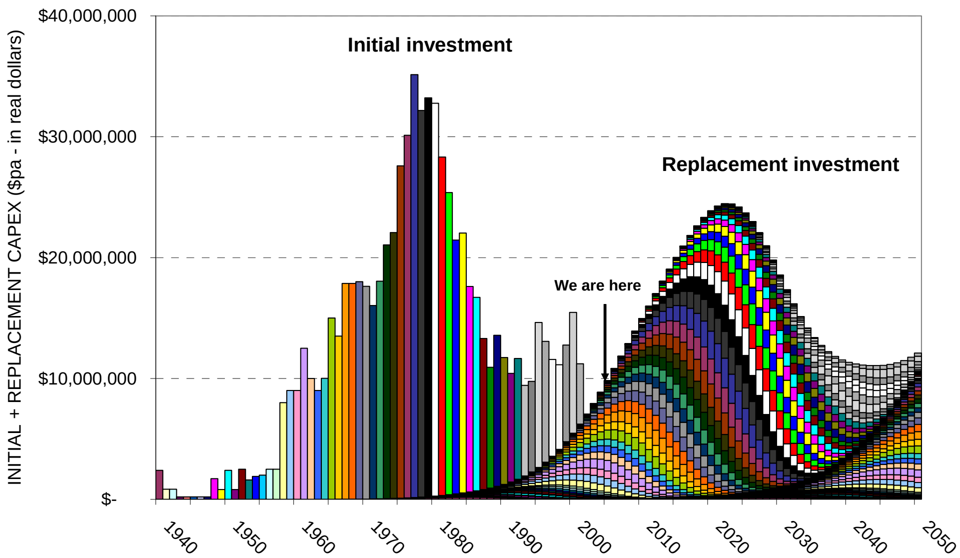
3 Trend analysis and aging infrastructure

It is common practice when assessing future expenditure requirements to use past expenditure levels as a guide. Trend analysis is useful, and often in the face of uncertainty it offers useful guidance. Nevertheless, as the Australian electricity industry moves into the replacement cycle the past may not provide an adequate or reliable guide to future expenditure requirements.

With an average life of 50-60 years, network assets installed in the 1950s are now entering the final stage of their useful life. Approximating a normal distribution curve, some equipment will already have been replaced while some may last a further 20 years. Nevertheless, the demand for replacement is now approaching levels that require specific attention to its funding. The alternative of "refurbishing" the existing asset base does not eliminate the need for additional expenditure; it simply shifts the financial requirement from capex to opex.

To illustrate the cycle of initial investment and its subsequent replacement, Figure 5 presents a replacement schedule for a distribution network. The first cycle, commencing in 1940, traces the initial wave of annual network investment, measured at replacement cost in $2003. The second cycle, commencing in the 1980s depicts the estimated replacement schedule for the initial investment. The replacement schedule has been estimated using a Weibull distribution function[2]. The average life of assets has been set at 50 years.

Figure 5: Investment and replacement cycles



In this example, replacement investment should have commenced around 1980. By 2005 it would be expected to reach a level of $7.5M, an amount equal to, or exceeding its annual business-as-usual capex requirement. Rising each year, replacement investment peaks at $25M in 2025, more than three times the annual capex budget. Though the investment requirements obviously will vary for each individual network, the replacement "shadow" is a well recognised phenomenon and is widely used to estimate the magnitude and timing of replacement investment.

[2] A Weibull function is a "survivor curve" distribution function developed specifically for estimating asset life expectancy and the concomitant replacement schedule for electricity distribution networks. It is similar in nature to the normal distribution curve.

Within this framework, it is evident that the use of past expenditure levels provides, at best, only a guide to forward-looking capex and opex allowances. Given Australia's aging electricity networks, it is not recommended that future expenditure allowances be constrained to past levels. Recognition of the demand for replacement investment would need to be factored into forward looking expenditure assessments.

4 Distribution: Cost structure analysis - 2005

The 2005 pricing review is the first by the ERA, the recently established independent pricing regulator. This contrasts with networks in other jurisdictions where such regulatory oversight has been in place for up to 15 years. On this basis a necessary first step is to consider the adequacy and comparability of revenues established under the previous regime before turning to an assessment of proposed future expenditures.

Accordingly, the cost analysis is in two parts; an examination of the current data (2005) and of future data (2006). We would caution however that large increases in regulated expenditures in Queensland and South Australia, which will take affect from 2006, tend to make the 2006 analysis more relevant for comparing network performance.

4.1 Scope of Western Power's network: business conditions

Western Power, along with ETSA Utilities and Aurora Energy, differs from the other Australian network businesses, in that it provides a network service effectively for an entire state[3]. Combining CBD, urban, and rural regions into one network business it could be expected to exhibit different cost outcomes to those networks with more specific operating environments, for example, the CBD of Citipower, the high density urban of AGL, the low density urban of Integral, or even the rural Country Energy or Powercor. This limits the number of useful comparable networks.

To overcome this limitation, data for the individual networks in NSW, Victoria, and Queensland have been aggregated to provide three additional statewide networks. With customer densities and other conditions more akin to those in Western Australia this approach increases the number of useful comparators in order to provide more reliable information on the relative position of Western Power. Key operating conditions for the networks included in the study are set out in Table 2:

[3] For the purposes of this analysis, Western Power's south western distribution network is regarded as equivalent to the interconnected systems of South Australia and Tasmania.

Table 2: Networks included in study: key operating conditions

Network	Connection density (connections/km)	Customer class (kWh/connection)
Western Power	**10.4**	**13.4**
South Australia	9.5	13.7
Queensland	9.9	17.8
Tasmania	10.7	14.2
NSW	11.4	16.7
Victoria	16.3	14.3
AGL	41.0	14.5
CitiPower	77.7	20.1
Country Energy	4.1	14.0
EnergyAustralia	32.0	17.0
Energex	32.3	16.2
Ergon	4.3	21.0
Integral Energy	24.0	18.3
Powercor	7.6	15.8
TXU	14.4	11.8
United Energy	49.0	12.2

4.2 Scope of Western Power's distribution network: voltage levels

There is one further aspect of network operation where Western Power may differ from other networks in the sample, and that relates to the scope of its network. Typically, Australian networks operate at two levels; transmission (high voltage) and distribution (low voltage). There is no standard cut-off point between these two functions with respective voltage levels driven by operational conditions such as the distance and size of load, history of load growth, or other factors.

Moreover, the demarcation tends to change over time. With increasing load, voltage levels at which energy is transmitted tend to rise to lift efficiency of grid operation. The superseded, mid-range network assets, referred to as sub-transmission, typically become part of the distribution network. In Western Australia, however, these sub-transmission assets are still retained by the transmission business. Effectively, based on asset values, this reduces the cost base of the distribution network by around 24 per cent, relative to those networks combining distribution and sub-transmission (Table 3).

Table 3: Western Power: distribution network cost base allocation

	Asset base - 2005
Distribution network	$1,962,266,000
Subtransmission network	$ 604,920,323
Combined networks	$2,568,146,323

At the same time, this structure nearly doubles the size of the transmission network relative to the other transmission operators. This aspect adds additional complexity to the task of comparing Western Power's network cost structures and estimating appropriate costs. Cost estimates drawn from statistical analysis of the other Australian networks will over-estimate the costs appropriate to Western Power's distribution only network. Accordingly, we have developed an indirect approach to the estimation of its costs.

Firstly, we have used the data for the combined network to statistically assess the relative cost performance of this business. Statistically this methodology is sound since the other networks in the sample combine both functions. The margin identified between actual performance and predicted performance is then used to estimate the comparable under or over cost position of the distribution only business. As it could not be expected that costs can be estimated with pin-point accuracy, a range of plus or minus 10 per cent is provided. Consider this worked example:

Example: Equation: Customer class and total revenue/connection

Average connection costs = 29.761x + 75.209

Estimated cost/connection Western Power combined = $526

Actual cost/connection Western Power combined = $467

Margin between estimated cost and actual cost = +13.0%

Estimated cost Western Power distribution only:

Actual cost/connection $358 plus 13.0% = $405

Range of expected costs per connection = $365 - 445

The distribution only network has been included in the charts to demonstrate clearly the impact that its structure has on its relative cost outcomes.

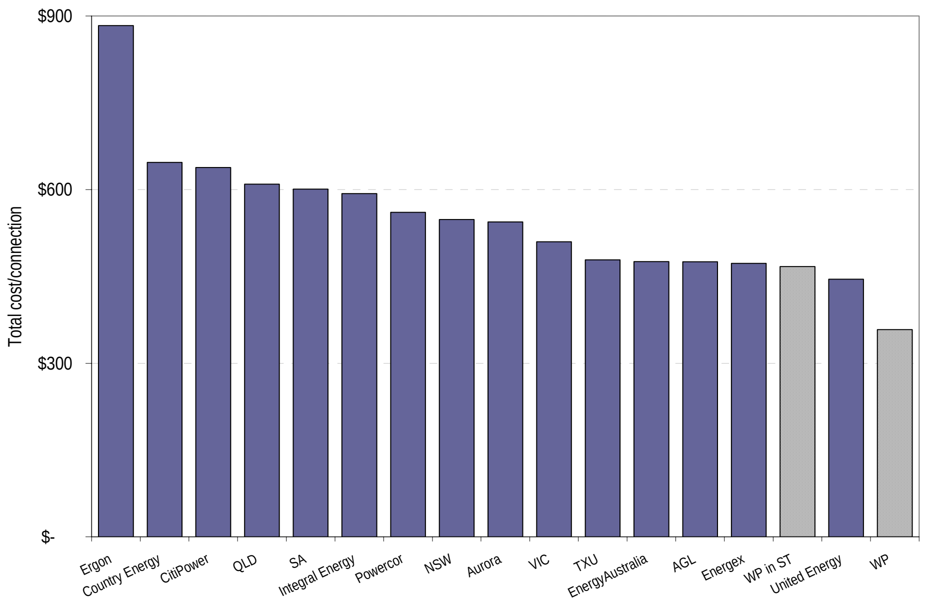
4.3 Network cost analysis

As a capital intensive industry, capital related charges represent around 70 per cent of total regulated revenue. Accordingly this review will address the whole cost structure including the asset base, return of, and on, capital, and operating and maintenance (opex) and capital expenditures (capex). Over or under expenditure can occur at any point in the cost structure.

4.3.1 Total revenue: cost and price

We commence by comparing Western Power's overall cost and price levels; with and without the subtransmission margin. In this instance cost is measured as total cost/revenue per connection and presented in Figure 6 ranked from highest to lowest. Western Power emerges as the least cost network in Australia; nearly 20 per cent below the next lowest network. This is not unexpected since it does not include sub-transmission costs. Including subtransmission increases costs, however, it does little to change its low cost ranking. Normalising costs against peak capacity (MW) produces a similar outcome. This low cost position is accentuated if we compare Western Power with the more appropriate whole-of-state networks (Table 4).

Figure 6: Network costs: total costs/connections: 2005



The average cost for these systems is $560 per connection, 20 per cent greater than that of the combined Western Power network.

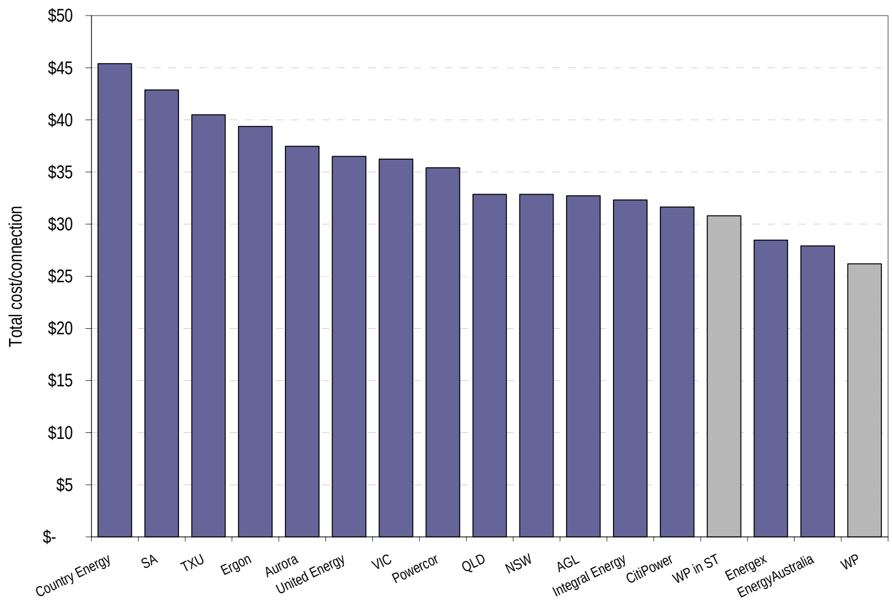
Table 4: Total costs/connection - whole-of-state networks

	Connection costs ($/connection)
Western Power – excluding sub-transmission	$358
Western Power – including sub-transmission	$467
Victoria	$510
Tasmania	$544
NSW	$549
South Australia	$601
Queensland	$609
Average – other states	*$560*

This comparison is presented as a guide only, as business conditions can affect relative connection costs. Nevertheless, as a starting point for this cost structure analysis it provides a useful benchmark. There may be acceptable reasons for Western Power's relatively low cost position; its network may benefit from a favourable operating environment or it may have surpassed the other networks in the efficiency of its operation. However, it is also possible that its current revenue allowance may be unjustifiably low and insufficient to maintain the network in good operating condition.

Price, measured as total cost/MWh, is examined in Figure 7. Including the subtransmission margin, Western Power is among the lowest priced networks in Australia, and considerably below the whole-of-state networks. Note that Western Power has one of the poorest load factors in the sample.

Figure 7: Network prices: Total costs/MWh



It is possible that favourable business conditions have contributed to this outcome. To test this proposition, Figures 8 and 9 examine the influence of connection density and customer class on total network costs.

Connection density: Connection density is the dominant cost driver for distribution networks. Western Power's connection density for both networks is 10.4. Connection density and average line costs ($/km) are depicted in Figure 8. To provide a more detailed view of the cost position of Western Power relative to the trendline and to comparable networks, only the low density networks have been included. The trend line, however, is that derived from the analysis of the whole sample shown in Figure 1.

Both Western Australian systems lie below the trendline. While the inclusion of the subtransmission network lifts the cost level closer to the trend, the average line cost of $4,600/km for Western Australia is significantly less than that for comparable networks such as South Australia, $5,700 or Tasmania, $5,800.

Equation 1: Connection density and total revenue per km

Average line costs = $4.6715x^2 + 228.59x + 2655.9$, R^2 98%

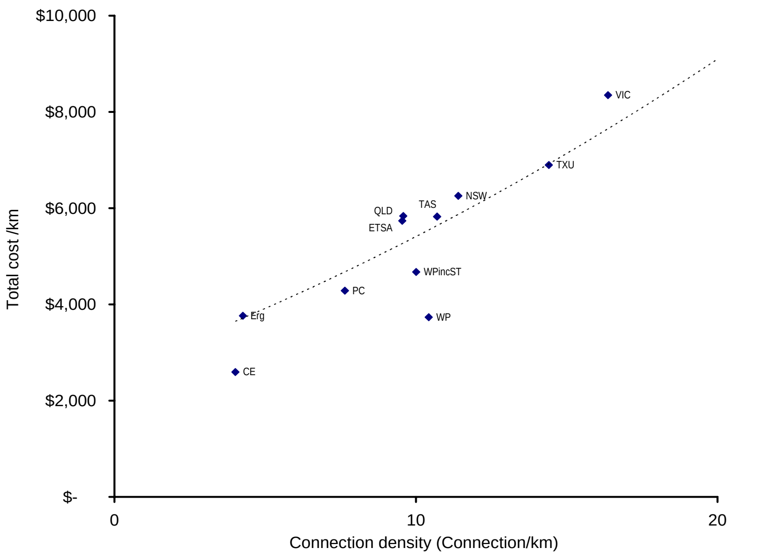
Estimate cost/km Western Power combined	= $5,400 per km
Actual cost/km Western Power combined	= $4,675
Margin between estimated cost and actual cost	= +15.5%

Estimated cost Western Power distribution only:

Actual cost/km \$3,735 plus 15.5% = \$4,314

Range of expected costs per km = \$3,885 - \$4,745

Figure 8: Connection density and network costs: connections/km and \$/km



Given the consistent above trend performance of the whole-of-state networks, the estimate from Equation 1 should be regarded only as a minimum.

Customer class: On average, end-users connected to the Western Power distribution network consume 13,700 kWh each year. This is at the lower end of the range for the Australian networks and below the average 15,200 kWh for the combined network. A number of large end-users are supplied directly from the higher voltage network. Figure 9, depicts the relation between customer class and average connection costs.

Several points merit note. First, there is considerable divergence around the trend line reflecting the influence of factors other than the type of end-user connected to the network. Next, despite this variance the whole-of-state networks are consistently close to the trend, according it a fair degree of predictability for Western Power's costs.

Average connection costs appropriate for a network similar to Western Power are estimated at:

Equation 2: Customer class and connection costs

Average connection costs = 29.761x + 75.209

Estimated cost/connection Western Power combined = \$526

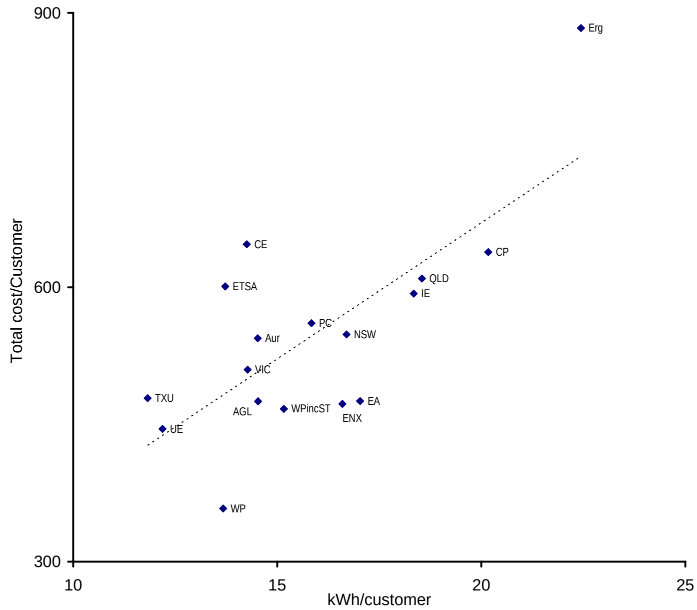
Actual cost/connection Western Power combined = \$467

Margin between estimated cost and actual cost = +13.0%

Estimated cost Western Power distribution only:

Actual cost/connection \$358 plus 13.0%	= \$405
Range of expected costs per connection	= \$365 - 445

Figure 9: Network costs and customer class: \$/MW and kWh/connection



However, the range of costs for networks with average consumption similar to that of Western Power is quite high. For example, South Australia, the network with the greatest similarity to Western Power, has average connection costs of more than \$600, while Country Energy costs are \$647 and Ergon's reach as high as \$883. These costs are well outside the range of costs indicated for Equation 2. These networks, along with Western Power, are the longest in the sample. It appears that supplying a network connection over a greater area of service territory raises the average cost of connection. For this reason we consider that the trendline in Figure 9 presents an indicative minimum cost level only for Western Power's distribution network.

Based on the cost estimates provided by Equations 1 and 2, a network with business conditions similar to Western Power distribution could be expected to have annual revenues between \$343M and \$364M, or a minimum increase of 13 per cent above the existing cost base of \$303M.

Total revenue:	Line length 81,295 km @ \$4,314/km	= \$364M
	Connections 847,529 @ \$405 / connection	= \$343M
Total revenue:	Range: \$364 - \$343, Average: \$353M	

The next section examines the individual building blocks and capex to determine which component has contributed to the shortfall in total revenue and to identify any special circumstances that might offer a plausible explanation.

4.4 Asset base

The *value* of the asset base affects the capital cost component of the revenue requirement; that is, return of, and on, capital. In contrast, operating and maintenance and replacement/refurbishment capital expenditures are determined by the extent of the *physical* asset base. However, the link between the value of the asset base and the quantity of physical assets is not as direct as it might seem. Significant implications for network revenues and cost comparisons emerge.

4.4.1Capital contributions

In certain circumstances, capital contributions are made to the network businesses by end-users or their agents for specific network assets, for example, developments in new residential areas. The accounting treatment of these additional assets is problematic with wide variations among jurisdictions. Moreover, in regions with high load growth the tendency is to a relatively greater proportion of contributions. Queensland and Western Australia on average have markedly higher capital contributions than Victoria or South Australia.

There are further differences. In Queensland the contributions are treated as capital expenditure. That is, they are an addition to the value of the asset base, earning a return on, and of, capital, while the financial contribution is deducted from the annual revenue requirement in the year in which it is made. Western Australia, in contrast, treats the contributions as revenue and not as capital effectively breaking the link between the value of the asset base and the physical additions to the network.

For a regulated business, this presents a challenge. Once the physical assets are constructed, the network business assumes financial responsibility for ongoing operating, monitoring, refurbishment and replacement expenditures. These costs, which are considerable, will be determined by the extent of the physical network, although the regulated allowances to meet these costs will be based on the asset's value. This approach may be perfectly reasonable. However, it is argued that in Western Australia where asset values do not reflect the full extent of the physical network, it raises significant issues for sustainable funding.

The value of the asset base has two important roles in pricing regulation. First, it determines the level of annual capital charges, with the depreciation component directed to funding refurbishment and replacement. In Australia it is also frequently used to fund augmentation. Asset values also form part of a number of ratios used for comparing the efficiency of network cost performance; for example, capex/assets, opex/assets, or assets/connection. If the assets used in the denominator do not fully reflect the extent of network serviced by the expenditures in the numerator, the cost indicators will be misleading.

In Queensland and Western Australia it is estimated that as much as 30 per cent of the physical asset base has been funded by capital contributions accruing over the past 25 years. In Western Australia, this drives a substantial wedge between the depreciation available for replacement and the level of replacement necessary. It could also have a negative affect on the level of opex allowed as this tends to be linked to the value of the underlying asset. Mostly obviously, it presents a challenge for credible cost analysis or performance comparisons.

To address this issue, we have chosen to include the contributed assets in the value of the asset base used for the analysis. A large proportion of the assets have been embedded in the network for up to 25 years, and subsequently maintained, refurbished or even replaced by Western Power during this period. We believe, therefore, this approach presents a more accurate assessment of the financial requirement confronting Western Power. Analysis of network costs and the impact of business conditions will be more soundly based, while estimates of the various cost ratios will be more plausible. Estimates of efficient opex or capex based only on the value of the asset base and excluding capital contributions would not justify sufficient expenditures to sustain the network over the longer term.

4.4.2 Asset values and connection density

Connection density has a profound influence on network assets. The number of connections dictates almost the entire asset requirement for a given length of line:

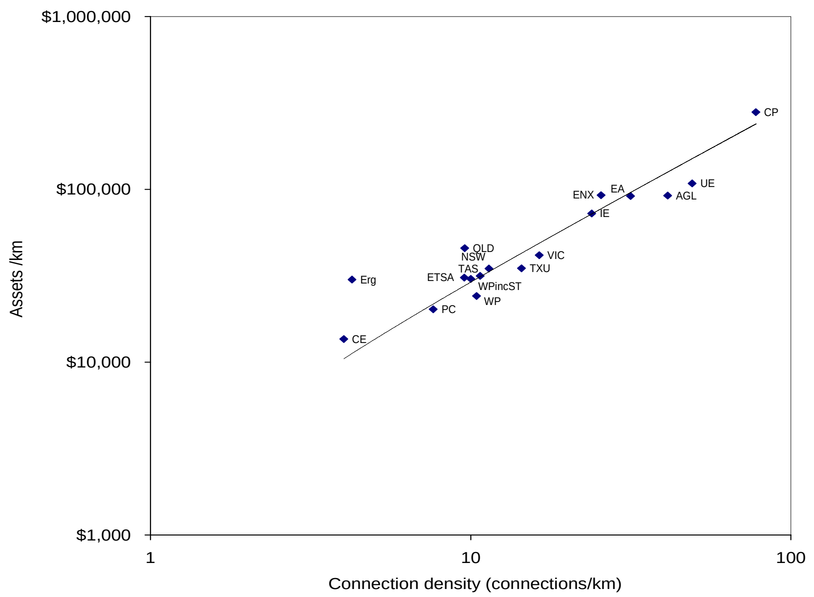
- underground or overhead system;
- type and spacing of poles;
- voltage of supply;
- number of circuits;
- number and size of transformers; and
- equipment redundancy.

As could be expected, Figure 10, which plots asset investment per km against density, replicates the robust link between total costs and density (Figure 1).

Variation around the trend line reflects differences at the margin in asset age (high load growth networks have relatively younger assets and hence relatively higher values eg Qld) and jurisdiction valuation policies. Victorian asset values, which were re-aligned at the time of privatisation for purposes of pricing uniformity, are consistently below those of the other Australian networks and, apart from Western Power distribution, the only networks on the right hand (lower) side of the trend line.

Note that inclusion of the subtransmission assets positions Western Power in line with its peers.

Figure 10: Asset investment and connection density ($/km and connections/km)



Projected asset requirements are:

Equation 3: Connection density and assets/km

Average connection costs = 3099.5x – 1987.1, R^2 91%

Estimated assets/km Western Power combined	= $30,279
Actual cost/connection Western Power combined	= $30,382
Margin between estimated cost and actual cost	= No change
Estimated cost Western Power distribution only:	
Actual assets/km $24,149	= No change
Range of expected assets per km	= $21,735- $26,465

Asset values, including capital contributions, appear in line with Western Power's distribution network connection density. We conclude that cost shortfalls observed in Equations 1 and 2 do not appear to be attributed to the value of the asset base.

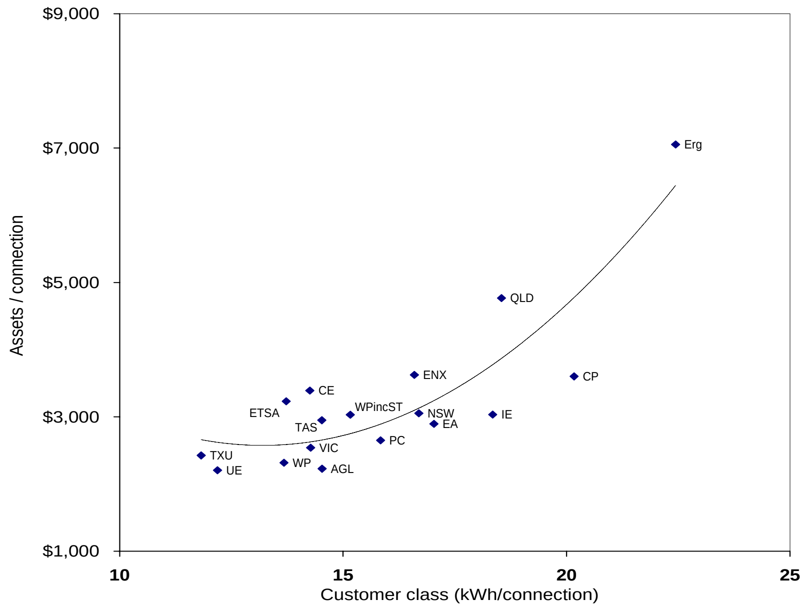
4.4.3 Asset values and customer class

Customer class can also influence the amount of assets required to connect end-users, with connection costs rising with increasing average consumption. However, the impact is more influential at the extremes, with large industrial and mining end-users often requiring atypical network connections.

Plotting customer class against average asset requirements, Figure 11 reveals a strong upward trend, especially for end-users with consumptions levels above 15,000 kWh. Closer examination reveals, however, that the trend line represents the average of two different groups of networks, the long, generally lower density networks and the shorter higher density systems. Western Power is one of the longer networks on the top side of the trend. Connecting end-users over a greater distance, on average, lifts the asset requirement for each connection by up to $500 per connection for any given level of average consumption.

While the relation between customer class and asset requirement is quite evident, the presence of two groups of networks in Figure 11 reduces the usefulness of the regression equation for estimating appropriate asset requirements for Western Power. However, its position relative to its peers suggests that its current asset investment is appropriate to a network with its configuration.

Figure 11: Asset investment and customer class ($/connection and kWh/connection)



4.5 Capital costs: return on investment and depreciation

The value of the underlying asset base is represented in annual regulated revenues as the rate of return on (WACC), and of (depreciation), capital. Network operating conditions may influence these charges but only indirectly through their impact on the asset base.

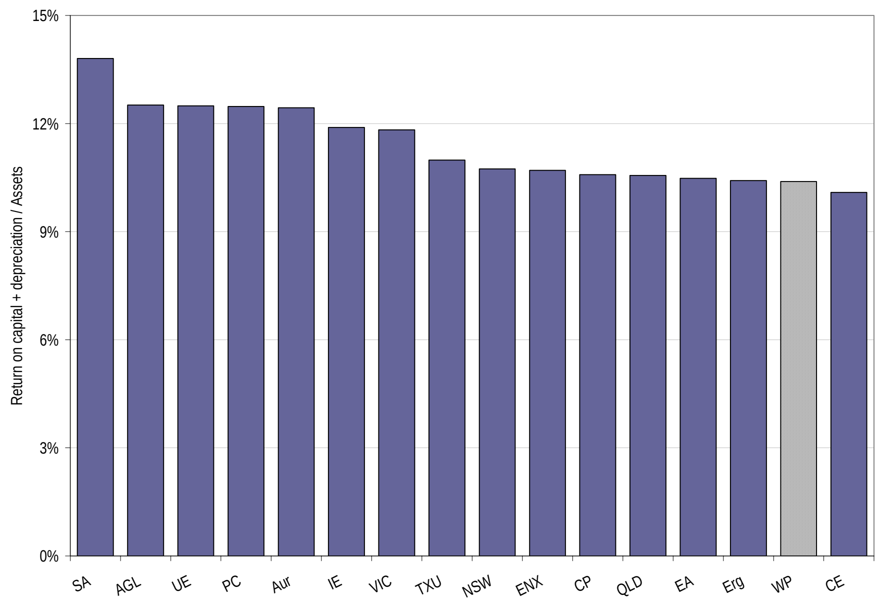
The purpose of the following analysis is to assess whether the level of capital charges offers any explanation for the identified revenue deficit. Recall, that capital charges for Western Power are based only on the "book" value of assets and not the whole asset base

4.5.1 Capital costs and the asset base

Ranking capital charges (return on assets plus depreciation) for the Australian networks, Figure 12 reveals the comparatively low level of charges for Western Power distribution. However, differing dates for network price reviews have resulted in a mix of regulated rates of return as there has been a declining trend in WACC over the past decade. This could partly explain the relatively higher ratios for the South Australian and Victorian networks.

For example, the South Australian regulator only recently released its pricing determination for the years 2006-2010 reducing the rate of return for ETSA Utilities to 6.8 per cent down from 8.3 per cent for the years 2001-2005.

Figure 12: Capital charges / asset base %



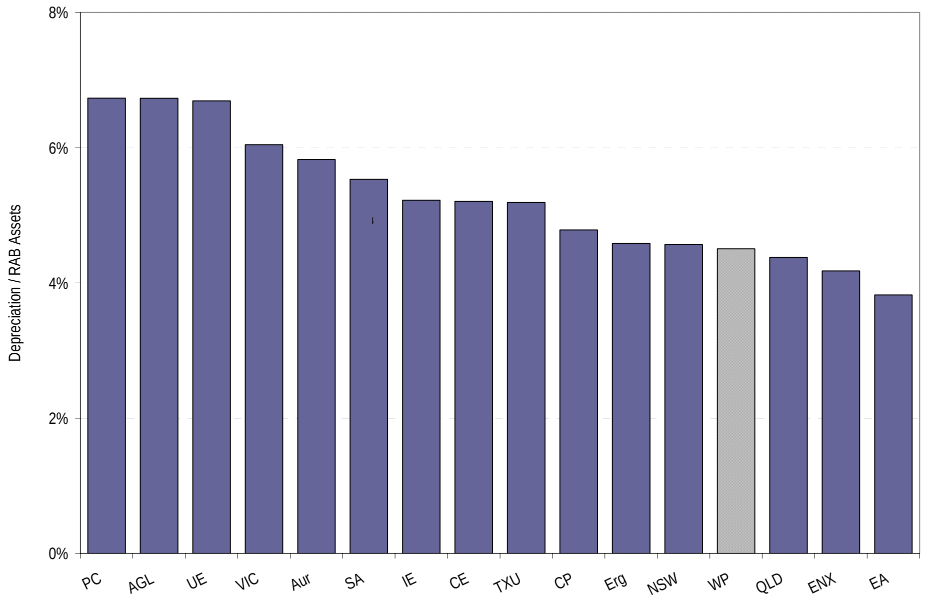
The affect of this change on its position is marginal; the capital costs/assets ratio for South Australia declines from 13.8 per cent for the first five years to 13 per cent for 2006-10, still considerably above the 10.4 per cent of Wester Power distribution only or combined.

Clearly, if the return to investment is calculated on only part of the asset base it will represent a significantly lower return when related to the entire asset base. For example, the annual return on investment for Western Power relative to its entire asset base is only 5.9 per cent, well below the 6.8 per cent allowed to ETSA Utilities earlier this year. Allowing a return on the entire asset base would lift the annual return to investment by $18M to $133M.

To remove the variation in the rates of return from the capital charges, Figure 13 ranks only depreciation. Several factors influence this ranking. For the NSW networks, IPART in its 2004 determination allowed deferred depreciation to offset the substantial increases allowed in operating and capital expenditures. For the Queensland networks, their relatively younger assets would affect this ratio since less of the asset base would have been written down. This appears to be confirmed by Queensland's relatively higher asset ratios (Figure 10).

With deprecation determined by part only of its network asset base, Western Power ranks at the lower end of the sample with an allowance equivalent to 4.5 per cent of total assets compared to an average of 5.3 per cent for the state wide networks. This reduces the relative contribution of depreciation to Western Power's regulated revenue requirement and would account for some of the revenue shortfall.

Figure 13: Depreciation / asset base %



The annual depreciation allowance for the distribution network is currently $88M, lifting the rate to 5.3 percent would increase this by $16M to $104M.

Capital charges are policy matters and not the concern of this cost review. Nevertheless, the physical asset base, irrespective of its funding, must be operated, maintained, and replaced over time. Depreciation, though defined in regulatory terms as a "return of capital" is routinely used to fund replacement or refurbishment expenditures. If Western Power is to receive a lower level of depreciation relative to its physical asset base, the reduction would need to be offset by commensurately higher opex and capex allowances to meet its unavoidable expenditure requirements.

Overall, we estimate that the convention of treating capital contributions as revenue and not as assets has reduced the annual revenue requirement by $34M each year. This is equivalent to 68 per cent of the $50M deficit in average annual revenues estimated in section 3.2.1.

We flag this as a critical issue for Western Power in any comparison of its expenditure ratios.

4.6 Operating and maintenance expenditure

Opex represents the final building block in the annual average revenue requirement. Though not determined directly by the network asset base, its extent and age are nevertheless key cost drivers. Connection density and customer class, through their influence on the underlying asset base, explain the major variance in this building block.

4.6.1 Opex and connection density

The ratio of opex to line length (opex/km) is a frequently used indicator for assessing relative performance. However, the strong relation with connection density requires that cost comparisons are only made after adjustment for the operating environment.

Figure 14: Opex and connection density (connections/km)

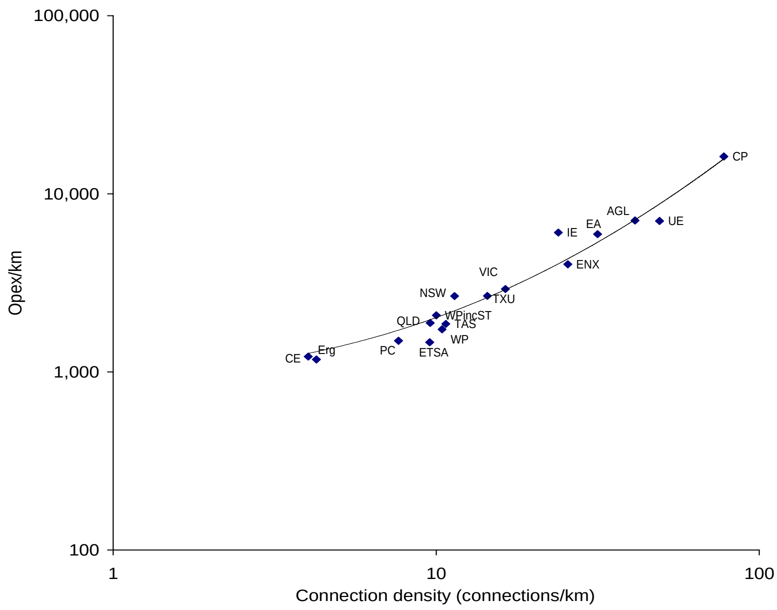


Figure 14 depicting opex/km and connection density demonstrates an exceedingly strong link. Including subtransmission, the Western Power ratio of opex to line length is in line with the industry trend. The equation for Figure 14 is:

Equation 4: Connection density and opex/km

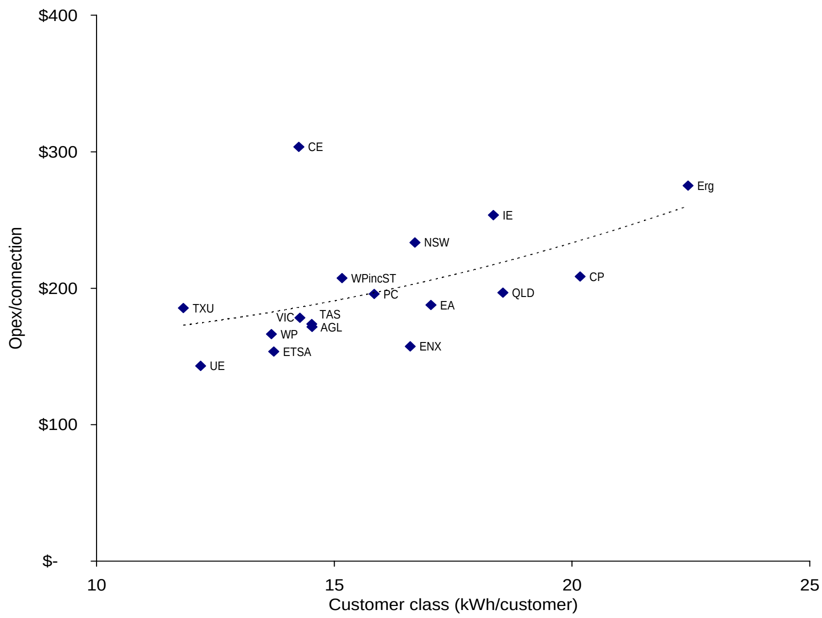
Average opex/km = $1.0532x^2 + 110.29x + 810.03$, R^2 96%

Estimated opex/km Western Power combined	= $2,081
Actual opex/km Western Power combined	= $2,076
Margin between estimated cost and actual cost	= No change
Estimated cost Western Power distribution only:	
Opex/km $1,735	= No change
Range of expected opex/km	= $1,560- $1,908

4.6.2 Opex and customer class

Opex/connection, another frequently used performance indicator, is less dominant in its affect than density. Its influence is more often evident at the extremes of average consumption levels. Figure 15 plots opex per connection and customer class. There is a clear and positive link between opex and customer class, but as observed with assets in Figure 11, there is greater variance around the trend than with connection density. There are several factors that could contribute to this pattern. The age of the asset base is particularly influential. The standout network at $300 per connection in Figure 15 is known to have particularly high ratio of aged assets. Accounting treatment of expenditures may also have an affect with expensing and capitalisation polices known to differ significantly between jurisdictions or even businesses.

Figure 15: Opex/connection and customer class



The presence of the outlier in Figure 15 reduces the usefulness of the trend for estimating appropriate levels of opex per connection. While the outlier does not affect the shape or gradient of the trend between opex requirements and average consumption levels, it will influence the level of opex for any given level of consumption. Statistically, it may be acceptable to omit this network from the analysis; however, its outlier position is known to be driven by several factors that, to a varying extent, now or in the future, will affect the other networks. It is an extremely long network, a factor that consistently lifts average connection costs above trend, with aged assets and a history of under-resourcing. It has increased annual opex over the past four years by 35 per cent as declining reliability necessitated large scale maintenance expenditures.

Western Power's combined network appears only marginally above trend. We conclude that Western Power's above trend position in Figure 15 reflects its relatively higher level of asset investment due to the greater length of its network rather than any over spend on its opex budget. This view is supported by its average opex performance when density is considered (see Figure 14).

4.6.3 Opex/assets

The ratio of opex to the underlying asset base is frequently used as a measure of cost performance. This indicator can be misleading. Ratios consist of two parts, a numerator and a denominator. The ratio of opex or capex to assets may convey information on relative expenditures but they may also convey information on the value of the asset base. It is not possible to determine the contribution of either the numerator or the denominator to the final outcome from this simple ratio.

Western Power would be disadvantaged by the use of this ratio since its operating expenditures are driven by the physical asset base while the denominator measures asset values, which do not include the 30 per cent of assets contributed by end-users.

4.7 Capital expenditure

Capital expenditure is more variable than opex. While the operating environment remains the dominant cost driver, other factors can exert a significant influence. The extent of the existing infrastructure, its age profile, and projected load growth combine in a number of ways to produce a more diverse outcome than opex which is more singular in its link with the asset base. Accounting treatment of capital contributions is another factor, with some jurisdictions grossing customer funded capex into the regulated capex allowance whereas in others it is netted out. For purposes of this analysis capital contributions has been removed from capex allowances.

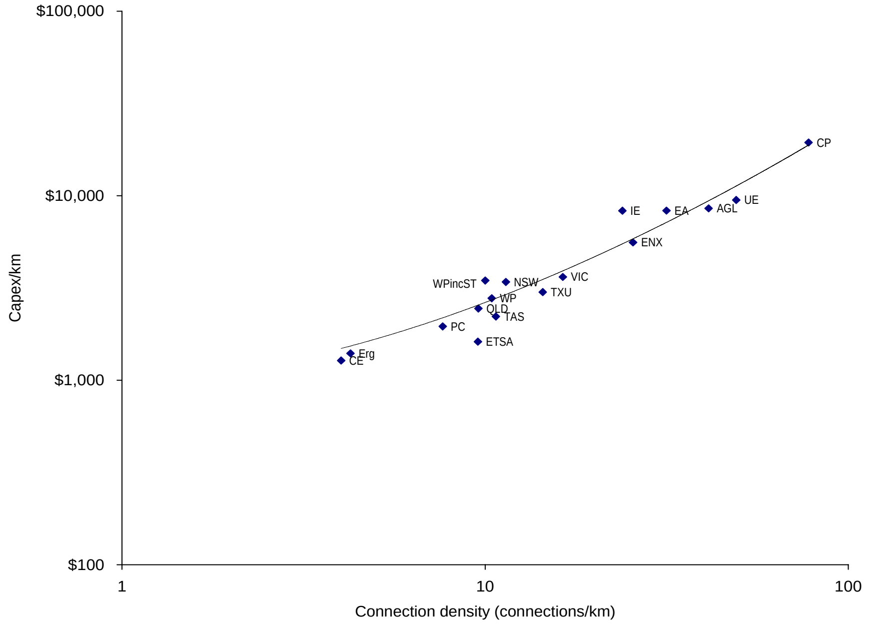
The rapid uptake of domestic air-conditioning, prolonged economic expansion, and concern at the reliability of aging infrastructure have resulted in an unprecedented increase in outlays for many of Australia’s distribution networks. Divergence around the trend will reflect the exposure of the individual networks to these factors.

4.7.1 Capex and connection density

Connection density remains the main influence on capital investment. Consider the substantial difference between the equipment required to provide a connection in rural areas and the major capital cities. Whereas rural end-users may be serviced by a single circuit low voltage line with widely spaced poles and little redundancy at a cost of $1,279/km, a CBD supply will consist of high voltage underground multiple circuits, with high levels of redundancy at a cost of $19,406/km. As a statewide network combining elements of rural, urban, and CBD densities, costs for Western Power are best compared with the other statewide networks included in this study.

Figure 16 depicts the relation between connection density and capex/km.

Figure 16: Capex/km and connection density



The estimated capex/km for Western Power distribution based on the equation for the regression line in Figure 16 is:

Equation 5: Connection density and capex/km

Average capex/km = $0.6304x^2 + 183.7x + 739.33$, R^2 95%

Estimated capex/km Western Power combined	= $2,699
Actual capex/km Western Power combined	= $3,470
Margin between estimated cost and actual cost	= - 28%
Estimated cost Western Power distribution only:	
Actual cost per km $2,780 – 28%	= $2002/km
Range of expected capex/km	= $1,800 - $2.200

Recall, that the use of the asset base excluding capital contributions for determining depreciation has been estimated to reduce funds available for refurbishment and replacement by around $16M per annum. To bring Western Power's funding into line with comparable networks this amount should be added to the capex ratio estimated above, that is capex/km of $2018/km or a range of 1,816 - $2,216.

However, there are several reasons why, in our judgement, this estimate does not represent the most appropriate guide to adequate capex levels for Western Power. Firstly, the data for Western Power already includes a substantial increase in expenditure that only emerges in a number of other states in the 2006 data. Concerns at declining reliability levels had prompted additional government funding which has been incorporated into Western Power's 2005 data. Next, Western Australia shares with Queensland the added pressure of strong economic growth and Australia's highest load growth. Queensland's regulated capex allowances more than doubled between 2005 and 2006.

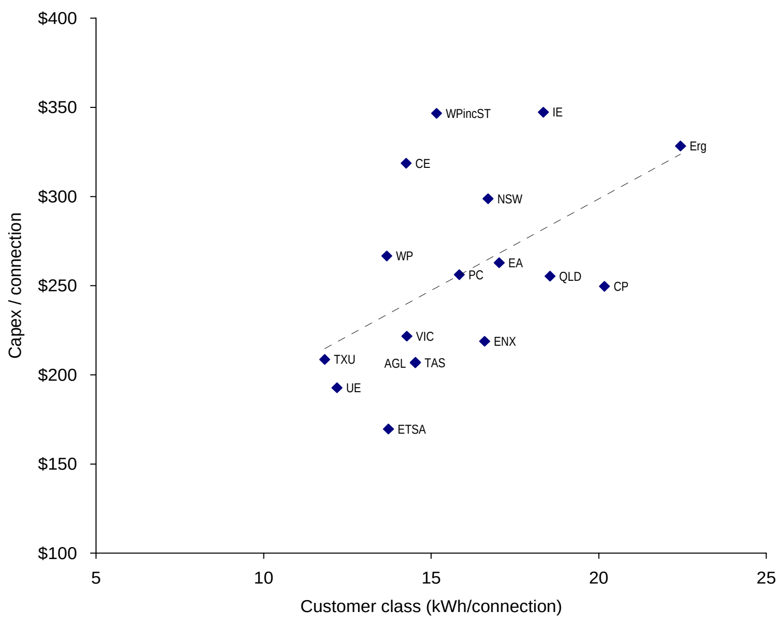
At best, the equation provides a guide only to an adequate capex allowance for Western Power.

4.7.2 Capital investment and customer class

Factors underlying the variability in the capex/connection ratio are less straightforward than those for capex/km. In part, this reflects the offsetting and stronger affect of connection density on connection costs. Average connections costs tend to rise with increasing consumption levels but to move in the opposite direction as density rises.

Figure 17, plotting capex/connection against customer class reveals a scattered link reflecting the more diverse factors influencing capital outlays. The extreme range of outcomes for networks with consumption levels similar to Western Power; $170 to $347/connection, make this equation inappropriate for robust estimation purposes.

Figure 17: Capex/connection and customer class



We believe that the unprecedented increases in capital budgets allowed in more recent pricing determinations have obscured the clear link that typically exists between capex and the type of customer connected. As noted previously, recent expenditures in Western Australia have had the affect of lifting its costs into line with expenditure increases to take affect from 2006 in the other jurisdictions.

4.8 Revenue and expenditure indicators for Western Power 2005

The cost analysis and performance comparisons presented in this report have identified a particular financing issue for Western Power. The accounting treatment of capital contributions as revenue and not as capital has driven a wedge between the asset value upon which the capital related building blocks are based and the physical asset base upon which opex and capex are based. This has the affect of reducing the level of depreciation below that typically associated with the value of Western Power's physical network. This deficit would need to be offset by a specific increase in the capex budget to provide adequate funding for refurbishment and replacement of the aging asset base.

Based on the analysis in the preceding sections we conclude that appropriate indicators, with acceptable range, for existing revenue and expenditures for Western Power distribution only network are as listed in Table 5.

Table 5: Western Power distribution: Revenue and expenditure indicators - 2005

Indicator	Estimated expenditure	Current expenditure	Change
Total revenue Range	$353M $343M-$364M	$303M	16%
Depreciation	$104M	$88M	18%
Total revenue / km Range	$4,314 $3,885 - $4,745	$3,735	16%
Total revenue/ connection Range	$405 $365 - $445	$358	13%
Assets/km Range	$24,149 $21,735 - $26,465	$24,149	N/C
Opex / km Range	$1,735 $1,560 - $1,908	$1,735	N/C

The changes in capital expenditure currently being allowed in other jurisdictions are so great that we do not consider it appropriate to provide an indicator for capex for 2005.

5 Distribution: Cost structure analysis - 2006

The preceding sections examined the level of expenditure allowances for the current regulatory period for Western Power. The task in this section is to estimate appropriate forward looking expenditure levels for the regulatory period 2006-2010.

Devising forward-looking cost estimates is a challenge since there are many unknowns, even in the relatively short time frame of five years. Additionally, the data for 2006 contains expenditure allowances from a mix of regulatory pricing periods. As recent pricing determinations have tended to allow substantially higher expenditures than those in previous periods, some data used in the 2006 analysis does not fully reflect the recent concerns over infrastructure reliability. Table 6 details the mix of regulatory pricing periods:

Table 6: Regulatory pricing re-set dates

South Australia	2006-2010
Queensland	2006-2010
NSW	2005-2009
Tasmania	2003-2008
Victoria	2001-2005

Note in particular that there is no 2006 data available for the Victorian networks since the current regulatory period expires in 2005. This will make appropriate comparisons more difficult. If the Victorian data is omitted from the 2006 analysis the sample size falls from 16 to 10 networks, allowing the more diverse networks to set the regression line. We have therefore opted to retain the Victorian 2005 data in the analysis. Given that recent regulatory determinations in other jurisdictions have allowed large expenditure increases, the most likely affect will be to depress the regression line at the margin. On average, the higher expenditure allowances for 2006 in South Australia and Queensland have raised the estimated level of opex per km for a network similar to Western Power by about nine per cent. The presence of 2005 Victorian data suggests this estimate should be regarded as a minimum.

The analysis in this section is restricted to an assessment of appropriate levels of operating and maintenance and capital expenditures.

5.1 Operating and maintenance expenditures 2006

5.1.1 Opex and connection density

The strong relation between average line costs and connection density is again evident in Figure 18. The increased opex allowed in the recent Queensland and South Australia pricing decisions has effectively lifted the regression line by around nine per cent above that observed in 2005. The equation for the trend in Figure 18 and the estimates for Western Power are:

Equation 6: Opex/km and connection density - 2006

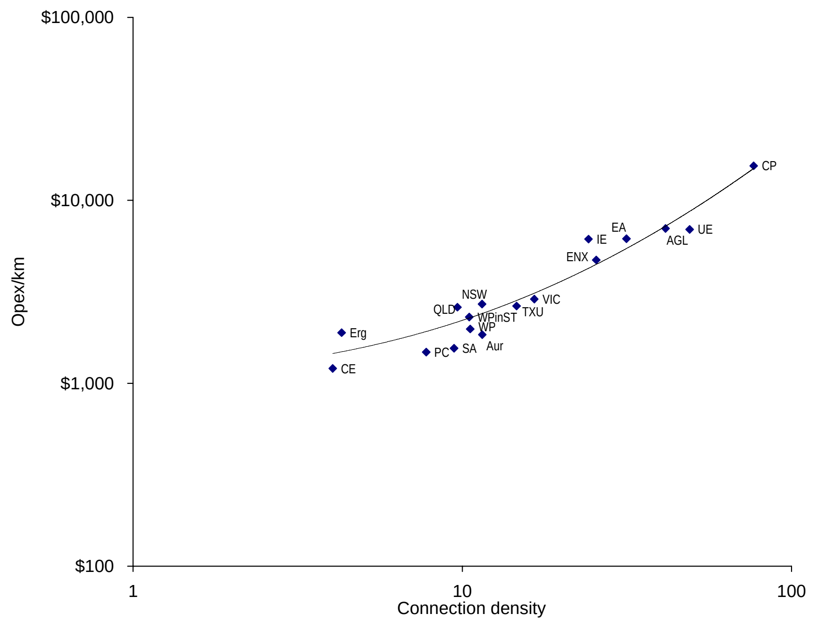
Average opex/km = $0.893x^2 + 113.48x + 988.37$, R^2 95%

Estimated opex/km Western Power combined = $2,277

Actual opex/km Western Power combined	= $2,300
Margin between estimated cost and actual cost	= - No change
Actual opex/km Distribution network $1,981	
Estimated opex/km –	= No change
Range expected opex/km	= $1,783 - $2,180

We are of the view, however, that the presence of the 2005 data for the Victorian networks has reduced the coefficients in the estimation equation. An examination of the scatter of networks around the regression line in Figure 18 reveals that the networks along and above the trend are those with more recent regulatory price resets. Assuming even modest increases in Victorian expenditures for 2006 would lift the regression line above the level of Western Power's projected opex.

Figure 18: Opex/km and connection density



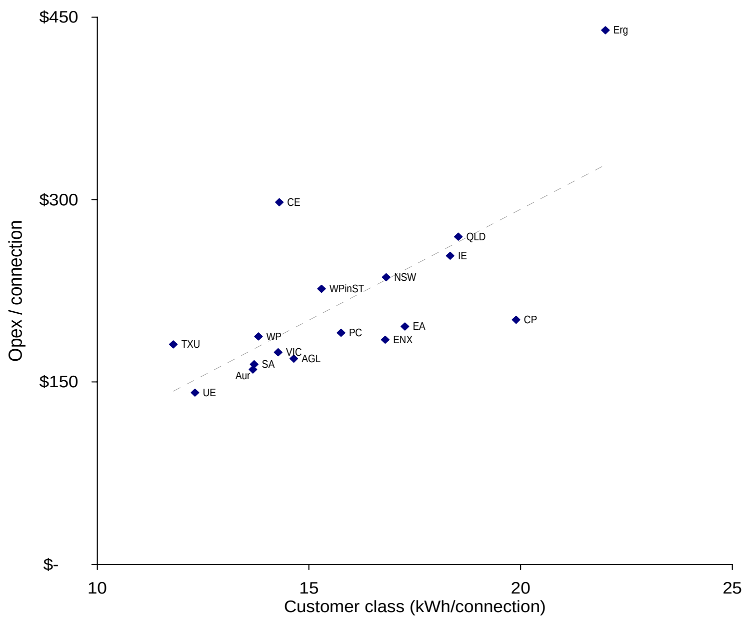
Indeed, it could be argued that Western Power's proposed opex budget for 2006 is quite moderate when compared to the relatively higher cost position of the statewide systems of Qld and NSW.

5.1.2 Opex and customer class

Though less robust than the link with connection density, the influence of customer type on relative costs is still quite evident (Figure 19). It is particularly notable at the extremes. Compare the average costs for networks with low average consumption $169/connection with, say, Ergon which connects large industrial and mining entities at a cost of $439/connection.

The presence of several outliers makes the use of the regression line from Figure 19 unacceptable for estimation purposes. However, the position of Western Power relative to the regression line and to other long networks, Country Energy, Ergon, and even TXU, suggest that its proposed opex for 2006 falls within acceptable limits for a network with its configuration. We would estimate that an acceptable level of opex per connection would be within the range of plus/minus 10 per cent of the projected level of $187, that is, $170 -$205.

Figure 19: Opex/km and customer class



5.2 Capital expenditures 2006

5.2.1 Capex and connection density

The impact of the recent pricing determinations is clearly evident in Figure 20 depicting capex/km and connection density. Compared to the 2005 data we observe a much greater variance around the trend line, with the R^2 declining from 96% to 83%. This is the lowest ever observed for the impact of connection density on any of the cost indicators.

Examining the scatter of observations around the trend in Figure 20 we note that the less robust result has been influenced by the most recent decisions in Qld and NSW, which have lifted capex for these networks significantly above the others, especially those in Victoria.

The equation and estimates derived from Figure 20 are:

Equation 6: Connection density and capex/km

Average capex/km = $0.0981x^2 + 222.09x + 1156.4$, R^2 83%

Estimated capex/km Western Power combined	= $3,510
Actual capex/km Western Power combined	= $3,800
Margin between estimated cost and actual cost	= -7%
For Western Power distribution actual $2,984 – 7%	= $2,775
Range for expected capex/km distribution	= $2,500 - $3,055

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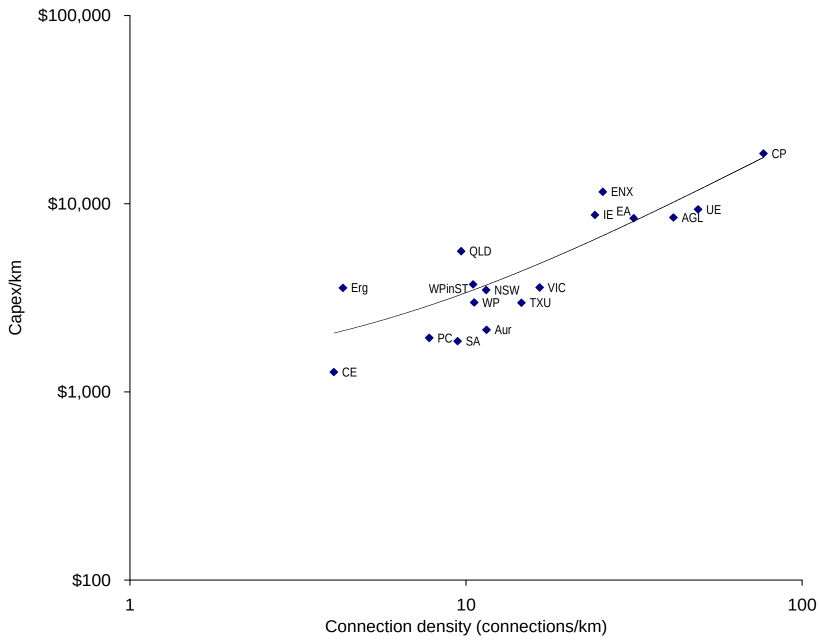
Figure 20: Capex/km and connection density



This estimate should be considered as a minimum only. The presence of the 2005 Victorian data has depressed the trendline which would be expected to rise to at least the level of Western Power combined once more recent data are included. Moreover, the similarity of conditions in Qld to those in Western Australia suggests that an appropriate range for capital expenditure for Western Power would be within the range set by the trend line and that of Qld; $3,505/km - $5,593k/m. To offset the reduced depreciation allowance identified in Section 3.4.1, an amount equivalent to around one per cent of the asset base should be added to the base amount.

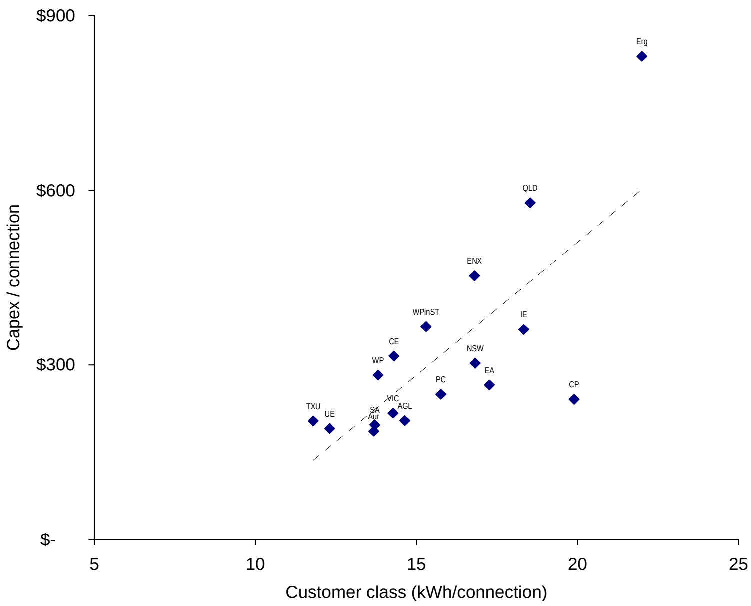
Specific factors such as the proportion of the network requiring replacement and the rate of projected load growth would determine the actual level within this range appropriate to the long term sustainability of the system.

5.2.2 Capex and customer class

An interesting feature of the expenditure increases in the 2006 data is the re-emergence of the link between capex and customer class (Figure 21). This is particularly evident for the lower density networks TXU, Western Power, Country Energy, and Ergon. Moreover, the difference between the low density networks lying to the left and above the trendline and the high density networks lying below and to the right is even more marked than in 2005 data.

As one of the lower density networks, Western Power combined lies above the overall regression line but well in line with the lower density networks.

Figure 21: Capex/connection and customer class



Since the presence of two distinct groups of networks means that the average is of little use in estimating expenditures for either the low or higher density businesses it is not possible to provide an estimate based on the equation in Figure 21. However, the position of the Western Power combined and distribution only networks relative to the industry trend in Figure 21 indicates that expenditure levels are appropriate to their respective customer class. We would estimate that an acceptable level of capex per connection would be within the range of plus/minus 10 per cent of the projected level of $282, that is, $255 - $310.

5.3 Expenditure indicators 2006 – 2010

Table 7 presents the expenditure indicators determined for Western Power for the price-reset period 2006-2010. The expenditures proposed by Western Power fall well within the ranges to be expected from a network with its scale and operating conditions. When compared to the statewide networks, the systems that offer the most appropriate comparisons for benchmarking cost levels, the proposals are reasonable and justifiable.

Several caveats relating to the cost analysis and the underlying data have been raised during the preceding discussions. These are repeated in this section to ensure that they form part of the assessment of the estimated cost indicators:

- Data are for 2006 but only 2005 for Victoria;
- Data are from a number of different pricing rounds and may reflect different considerations;
- Cost allocations between opex and capex are not uniform across the Australian jurisdictions. Accordingly, relatively high or low expenditure ratios may simply reflect accounting policies not cost performance; and
- Treatment of capital contributions can create distortions although steps have been taken to address this issue.

In general, these factors may have only a small influence on the cost outcomes. However, we consider that it is appropriate that the caveat be considered when assessing the estimated indicators.

Table 7: Western Power Cost indicators for projected expenditures

Indicator	Estimated Cost Average 2006-10	Range	Margin for range
Opex/km	$1,852	$1,783- $2,180	10%
Opex/connection	$1,87$	$170 - $205	10%
Capex/km	$2,775	$2,500 - $3,055	10%
Capex/connection	$282	$255 $310	10%

6 Transmission: Cost structures

6.1 Scope: Western Power's transmission network: Voltage levels

As discussed in the section on distribution, Western Power's demarcation between transmission and distribution differs from that of the other States. Sub-transmission forms part of the transmission business in Western Australian whereas it is operated as part of the distribution business in the rest of Australia. Effectively, based on asset values, this arrangement raises the cost base of Western Power's transmission grid by around 50 per cent, relative to those networks with transmission only (Table 8).

To allow comparison of the costs of Western Power's transmission plus sub-transmission business with businesses that provide a transmission only service, we have taken a two-step approach. In the first instance, we have compared the transmission only network on a basis with the other Australian transmission businesses.

Table 8: Western Power: transmission network cost base

	Asset base – 2005
Transmission network	$585,943,677
Sub-transmission network	$604,929,323
Combined networks	$1,190,864,000

We have then integrated the findings from the transmission analysis with that of the distribution analysis in the first section to provide an overall estimate of the expenditures appropriate for Western Power's transmission plus sub-transmission business.

6.2 Transmission networks: operating conditions

In contrast to distribution, there is only one transmission network in each jurisdiction, placing Western Power on a more equal footing for cost comparisons. However, given the considerable variation in population and geography, notable differences remain in the network operating environments. Table 9 presents the scale and key operating conditions for the transmission networks included in the study.

Table 9: Transmission networks: Scale and key operating conditions

	Length km	Peak demand MW	Average voltage kV	Energy density (MW/km)	Load factor
WA transmission	3,655	2,924	196	0.80	56%
WA Incl Sub-transmission	7,074	2,924	155	0.41	56%
NSW	12,570	13,100	250	1.04	62%
Victoria	6,619	8,974	289	1.36	59%
Queensland	12,107	8,200	220	0.68	66%
South Australia	5,635	3,026	193	0.54	47%
Tasmania	3,574	1,806	152	0.51	71%

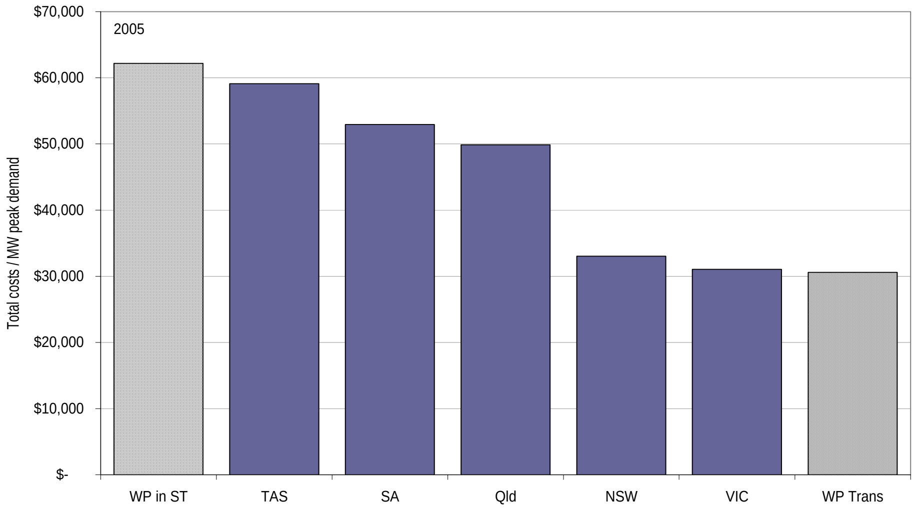
Note, that the peak demand for both WA networks is 2,924 MW. That is, both networks share the same customer load. This configuration reduces the energy density for the sub-transmission network relative to transmission by 50 per cent. The affect of this on expenditure levels appropriate to the two different networks is apparent from the following analysis.

6.3 Transmission network cost analysis

Following the format established in the distribution section, we commence by comparing Western Power's overall cost and price levels. Data for the combined network (transmission plus sub-transmission) has been included in the charts as a guide to the relative cost position of the combined network.

Average costs for the transmission networks, measured as total revenue/peak demand MW, are depicted in Figure 22.

Figure 22: Transmission costs – Total costs/capacity - peak demand MW



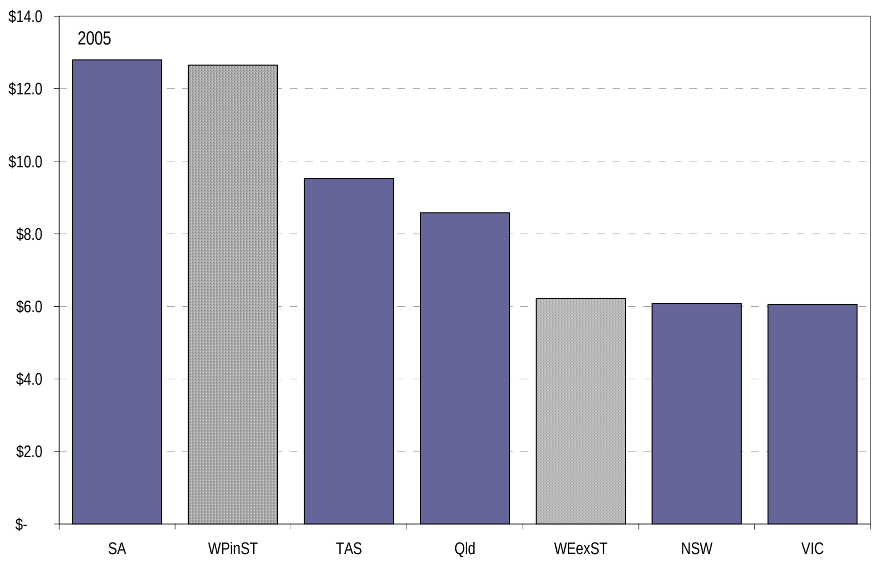
The transmission network of Western Power exhibits the lowest average cost of Australia's transmission networks. Notably, even the cost of the combined transmission and sub-transmission networks is little more than that for either Tasmania or South Australia transmission only. As different network configurations may give rise to different cost outcomes, the next sections will examine the role of operating conditions in this low cost position.

Transmission prices, measured as total revenue/MWh, are examined in Figure 23. The slightly higher average price for Western Power, relative to NSW and Victoria is due to its lower load factor (56%) relative to NSW (62%) and Victoria (59%), this means that it has fewer throughput units (MWh) over which to average its capacity cost base (see section 4.3.1).

To assess the influence that its operating environment may have on Western Power's relative cost outcomes, Figures 24 and 25 examine the link between total costs the two major cost drivers; energy density and load factor.

Energy density: In connecting generators to bulk supply points, transmission investment will reflect not only the length of the network required to provide the connection but also the level of the load to be transported. The investment decision will be based on a cost effective trade-off between distance, load, and losses. Overall, cost efficiencies are achieved by raising the voltage as energy density increases; this has the affect of reducing costs per MW capacity provided (Figure 24) while at the same time raising costs per line length (Figure 25).

Figure 23: Transmission prices - Total costs/MWh



The contrast in the direction of the two trend lines presents convincing evidence that simple partial indicators may provide misleading indications of comparative efficiency.

Measured against peak demand capacity (Figure 24), total costs for Western Power's transmission network lay substantially below that expected for a network with its middle range energy density. Figure 25, depicting average line costs and energy density confirms this finding.

While Figure 22 indicated that Western Power had the lowest average costs, equivalent to that of the high density NSW and Victoria networks, when the operating environment is factored into the analysis, it emerges that Western Power's costs should actually be much higher. In our experience a margin of the magnitude revealed in Figures 24 and 25 is not attainable simply on the basis of operating efficiency. It signals under-resourcing in some segment of the revenue stream.

Figure 24: Energy density and network costs - MW/km and total costs/km

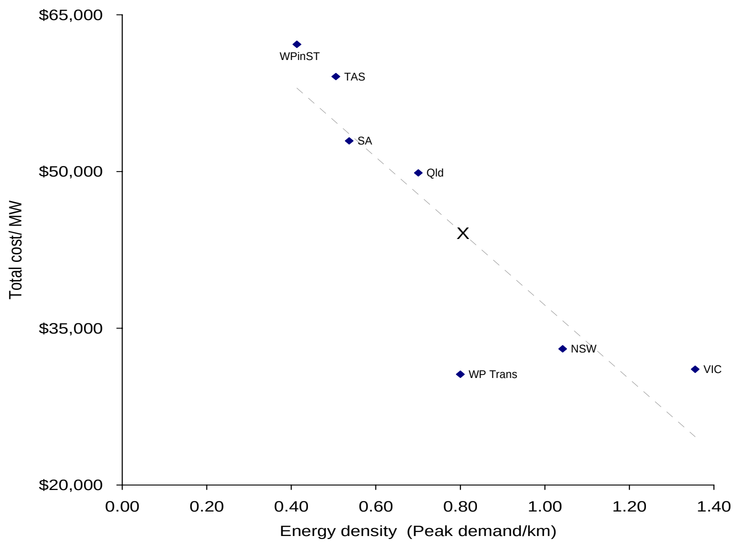
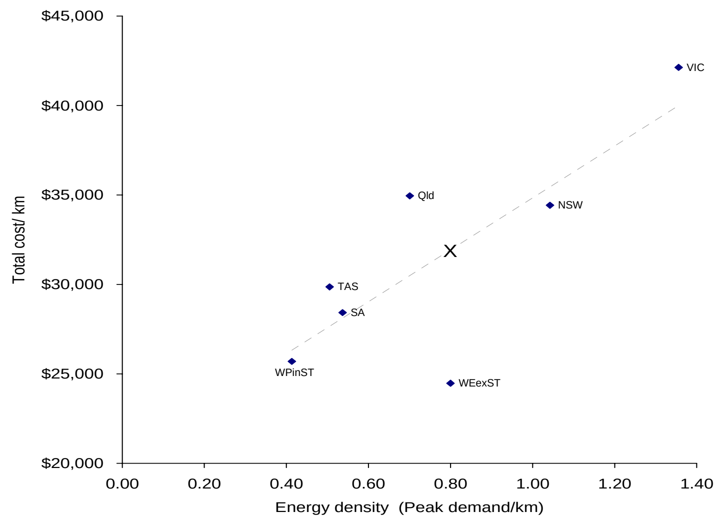


Figure 25: Energy density and network costs - MW/km and total costs/km



Though the number of networks in Figure 24 is limited, the trend line reveals a fit that is sufficiently robust to allow cost estimations for Western Power.

Equation 1: connection density and total revenue per MW

Average capacity costs = -35401 + 72620, R^2 75%

Estimated cost/MW Western Power-Transmission = $44,296

Estimated cost +/- 10% range $48,725 - $39,866

Current cost /MW $30,592

Load factor: While energy density measures the spatial element of the load, load factor provides an indication of the type of end-user comprising that load. Irrespective of whether end-users are connected directly to the grid or to the lower voltage distribution network, they will have some influence on the technical specification of the transmission grid and its cost structure. Meeting the demand of customers with high load factors, (MWh/MW), typically industrial or mining businesses, requires a more complex and hence more costly transmission network.

The impact of load on costs is best assessed by normalising costs against an indicator that can capture both the type of load and the distance over which it must be conveyed. One useful measure for this purpose, is a composite variable comprising line length * average weighted voltage level. This approach captures both the influence of the length of the network and the type and magnitude of the capacity provided. It offers the best fit with load factor since it captures more accurately than single variables the trade-off between customer type, distance, and voltage. Powerlink used a similar composite variable in its 2001 application to the Australian Competition and Consumer Commission, and this was subsequently accepted as a fair proxy for the network service.

Figure 26: Load factor and network costs (total revenue/km*kV)

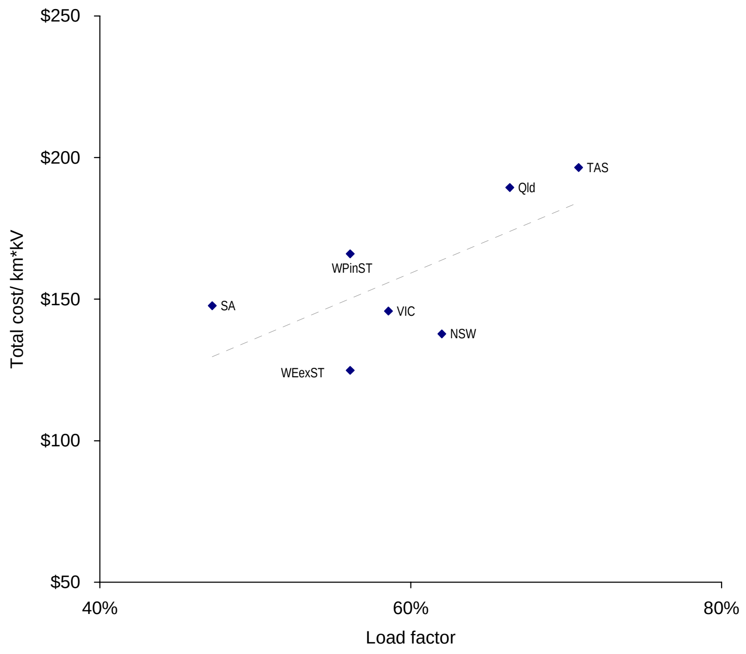


Figure 26 depicting load factor and average revenue per km*kV of network provided presents a clear and positive link between these two variables. Tasmania and Queensland which serve substantial mining interests have costs considerably greater than, say, South Australia which has Australia's lowest proportion of large end-users. Western Power lies considerably below the trend, and even the combined transmission and sub-transmission network only has costs in line with the other transmission only networks.

Equation 2: load factor and total revenue per km*kV

Average costs pr km*kV= -231.47x + 20.297, R^2 44%

Estimated cost/km*kV Western Power-Transmission = $166

Estimated costs + / - 10% $149 - $183 -

Current cost /km*kV $125

Based on the cost estimates provided by Equations 1 and 2, a transmission grid with business conditions similar to Western Power transmission would be expected to have annual revenues between $117M and $119M. This is 30 per cent above the current total revenue of $89M.

Total revenue: Line length - 3655 km @ $31,935 = $117M

Km*kV - 716563 @ $166 = $119M

Estimated revenue + / - 10%`` $130 - $105

The next section examines the individual building blocks and also capex to determine which component has contributed to the shortfall in total revenue and to identify any special circumstances that might offer a plausible explanation.

6.4 Asset base

As we have already observed, the asset base affects the capital cost component of the revenue requirements through its affect on the return on, and of, capital. Transmission is even more capital intensive than distribution. On average, Australian transmission businesses invest $6.6 in assets for each dollar of revenue, more than 25 per cent above the $5.2 required for distribution.

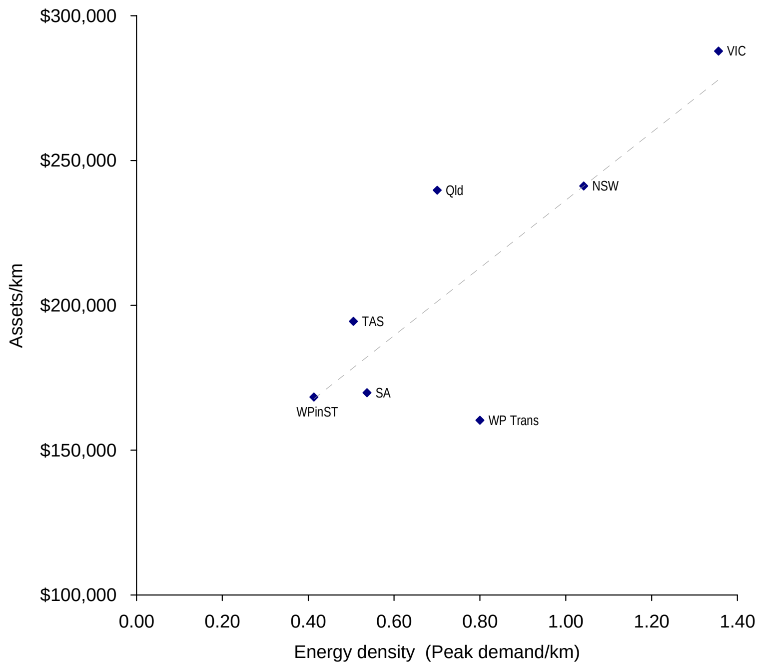
In contrast to the distribution sector, there is little in the way of capital contributions from developers or customers since transmission assets serve a much wider group of consumers than the more geographically discrete distribution systems. For Western Power this means that the value of its transmission and sub-transmission asset base will directly reflect the quantity of physical assets required to provide the high voltage service, in contrast to distribution where capital contributions drive a wedge between the two.

6.4.1 Asset values and energy density

Energy density is a major determinant of transmission investment. Moreover, with persistent load growth there is a continuing need to upgrade existing lines to attain the most cost effective mode of transport at the critical high voltage level. In areas of rapid growth in energy consumption this can place continuing pressure on grid owners. Queensland provides a useful example. Faced with rapid economic growth and the construction of new generators to meet the growing electricity demand, the investment requirement for new transmission has been substantial. This expansion has lowered the average age of assets but increased the average value of its asset base relative to the systems in the lower growth states of Victoria and NSW.

Plotting asset investment per line length against energy density, Figure 27 reveals the strong and positive influence of density on asset investment. Queensland, as could be expected, sits above the industry trend. In contrast, Western Power reveals an average asset value that is substantially below that of its peers. Combining transmission with sub-transmission, effectively doubling its asset value, only brings Western Power up to the level of the industry average.

Figure 27: Asset investment per km and energy density



Based on the trend line in Figure 27, estimated asset requirements for Western Power transmission are:

Equation 3: Energy density and assets/km

Average assets / km = 116,888x + 119415, R^2 66%

Estimated assets/km Western Power transmission	= $187,400
Current assets/km	= $160,330
Estimated appropriate total asset value	= $683,000,000
Estimated asset value + / - 10% range	= $751M – 615M
Current asset value	= $585,940,000

The difference between the estimated asset base appropriate to a network of Western Power's transmission system and the current value of that asset base is substantial. Factors that could contribute to this relatively low asset base outcome include the age of the infrastructure, or possible variations in valuation methodologies. From this analysis it is not possible to offer an informed view on the underlying cause for the shortfall identified, however, there is one other factor that may contribute some explanation.

Western Power has traditionally operated as a vertically integrated utility. In particular its networks, distribution, sub-transmission, and transmission were treated as a single business unit. Operating separation over the past few years has required that costs be allocated among these three components. It is possible that the allocation of asset values and costs across the newly independent businesses does not fully reflect the underlying cost position. Only with the benefit of experience over some period of time will the financial demarcation become more apparent. We would suggest some flexibility be provided in expenditure allowances to accommodate the possibility of cost re-allocations as the actual underlying cost position emerges.

Though this may offer some explanation for the relatively lower value of Western Power's transmission assets, the position of Western Power including sub-transmission relative to the trend line in Figure 27 does not suggest that such allocation issues are a significant contributor to the identified gap.

6.5 Capital costs: return on investment and depreciation

The purpose of the following analysis is to assess whether the level of capital charges offers any explanation for the revenue deficit identified in Section 7.3 and what contribution, if any, the relatively lower asset base has made.

The first stage in this examination is to compare the level of capital charges relative to the asset base for the Australian transmission businesses (Table 10). On average the total capital charges for Western Power are about one percentage point above those for the other networks. This appears to be due to its higher level of depreciation, 3.6 per cent of assets compared to around 2.2 per cent for the other networks.

Table 10: Capital charges/asset base

	Capital charges/ Assets %	Return on capital/ Assets %	Depreciation / Assets %
WA Transmission	11.36	7.7	3.6
WA + sub-transmission	11.36	7.7	3.6
NSW	10.17	8.9	1.3
Victoria	10.35	8.1	2.2
Queensland	10.54	8.3	2.2
South Australia	10.49	8.0	2.5
Tasmania	10.38	7.9	2.4

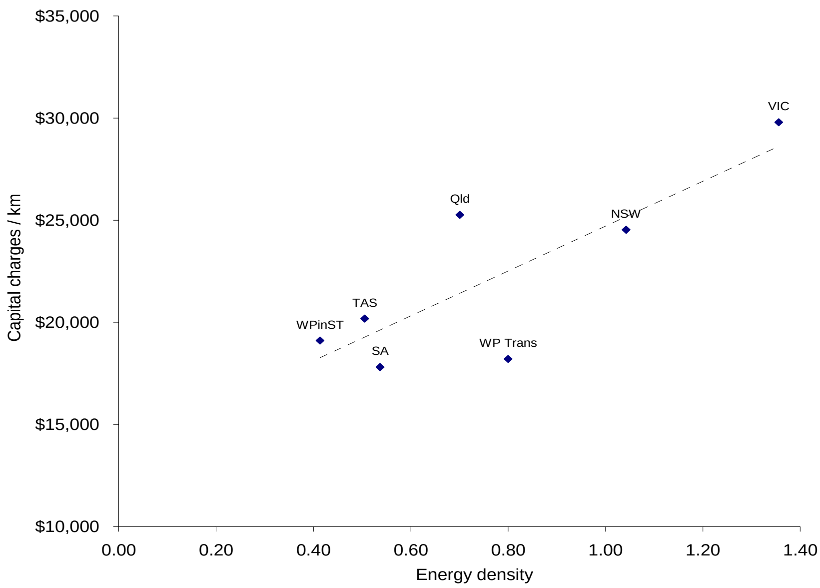
Note: the return on capital appears different to the rate quoted in the regulatory pricing decisions due to timing differences in the asset base calculations.

The depreciation rate for NSW appears anomalous since it suggests that its assets will be replaced over a period of around 75 years. While this may be appropriate for new assets, the infrastructure in NSW is among the oldest in Australia, with an average life expectancy that would fall well short of 75 years.

On balance, we would accept that the capital charges for Western Power transmission fall within a range that appears appropriate to the level of its asset base. If the rate of return and depreciation provide little explanation for the revenue deficit we must return to the level of the asset base itself.

Figure 28, plotting capital charges per km against energy density, reflects the pattern evident in the plot of assets and energy density (Figure 27) with Western Power once again well below the industry trend.

Figure 28: Capital charges per km and energy density



As we have already determined that the level of capital charges for Western Power is in line with the industry standard, the gap revealed in Figure 28 can only be due to the relatively lower level of its underlying asset base.

To test this assumption, we increase the value of the asset base to that estimated in Equation 3, $683M, and then calculate commensurate capital charges using the rates for Western Power transmission shown in Table 10. Lifting the annual capital charge to around $77M, up by $10.7M from the current level of $66M, this increase in the asset base would account for around 40 per cent of the $27M revenue deficit identified in Section 7.3. The capital charges/km ratio for Western Power transmission in Figure 28 would rise to $21,115, approaching closer to the industry standard, although still below the trend line estimate of $22,504.

We are of the view that the value of the existing asset base is at least $97M below that appropriate to a transmission network of the configuration of Western Power transmission. In turn, this has lowered the level of the capital charges accruing to the business by around $10.7M per year and likewise the level of total revenue.

6.6 Operating and maintenance expenditure

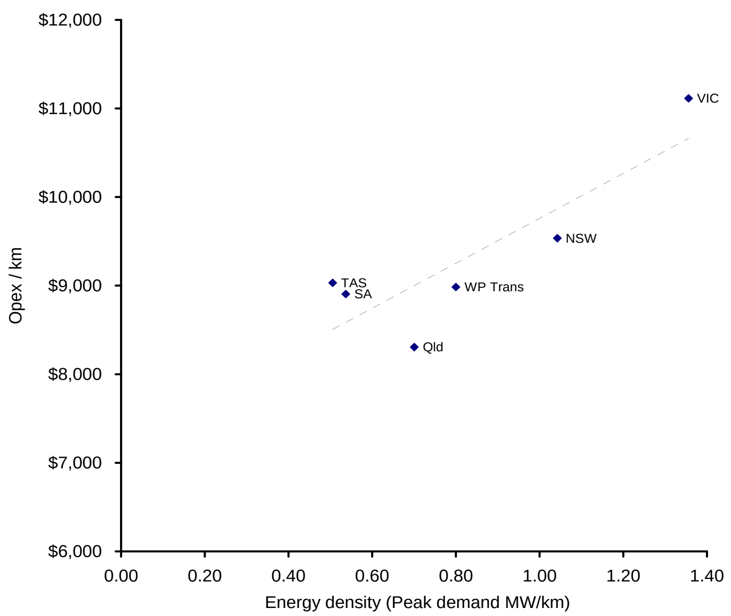
Though the level of operating and maintenance expenditure is not determined directly by reference to the asset base, the extent of the network and its age are, nevertheless, key cost drivers.

6.6.1 Opex and energy density

The ratio of opex to line length (opex/km) is one of the most frequently used indicators for assessing relative cost performance. However, unless adjustment is made for differences in energy density, this measure is just as inappropriate for transmission as it is for distribution.

Figure 29 depicting opex/km and energy density once more presents evidence of the clear and positive link between energy density and network costs. Opex costs for Western Power are again below the trend. The low level of costs for Queensland has tended to lower the industry average possibly increasing the gap between Western Power and the industry average. Queensland's relatively low opex ratio is the outcome of its asset management practice. For some time it has been stated network policy to minimise opex by "working the assets hard", and over the longer term to refurbish or replace assets where necessary.

Figure 29: Opex / km and energy density



In a network with rapid load growth this approach can be cost effective since the increasing demand could otherwise "strand" smaller plant or lower voltage lines. Queensland's distribution businesses had adopted a somewhat similar approach although the regulator in its recent pricing decision awarded significant expenditure increases to upgrade the networks which it believed had suffered from restricted expenditures.

Estimated opex for Western Power based on the trend in Figure 29 is:

Equation 4: connection density and opex/km

Average opex/km = 2535.1x + 7224.7, R^2 73%.

Estimated opex/km Western Power transmission	= $9,253
Estimated range	$10,178 - $8,328
Current opex/km	= $8,985

Analysis of opex against capacity (MW) and km*kV exhibits a similar outcome to Equation 4. On the basis of the estimate derived from Equation 4 we find the level of opex in 2005 acceptable for Western Power's transmission network. The variation of less than three per cent between the actual and the estimate is not statistically significant. However, given the influence of Queensland on the down side of the trend, any variation is likely to be on the upside rather than in any reduction from current levels.

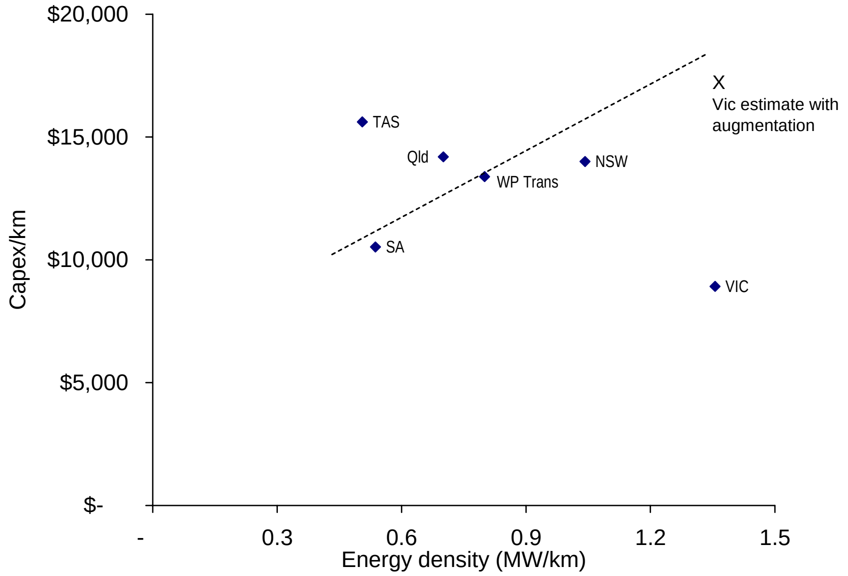
6.7 Capital expenditure

Capital expenditure for transmission businesses is volatile when measured on a year to year basis. Augmentation tends to be lumpy, and on average, quite large as incremental capacity is provided to meet load growth or allow access for recently constructed generators. It is not uncommon for capex budgets to double and then halve from year to year as augmentation demands are met. Use of single year data can give quite misleading results. For this reason, analysis of capital expenditure for 2005 uses annual average data. For the purposes of like-with-like comparisons, the averages are derived from the first round of pricing, typically for the period 2001-2004. Western Power's data are averaged over the period 2003-2005.

6.7.1 Capex and energy density

The link between capital expenditure, measured against line length, and energy density is depicted in Figure 30. Though the typical strong and upward relation between the two variables is evident, the two outliers require comment. Victoria's structural separation of the maintenance and replacement of the existing grid from its augmentation effectively reduces the annual capex budget of SPI PowerNet by around 50 per cent relative to the other Australian transmission businesses. Tasmania, with a recognised history of under-resourcing and the imminent opening of the Bass Link has been awarded substantial increases in its capex budget to allow it to meet required security standards.

Figure 30: Capex / km and energy density



The trend line in Figure 30 represents a best fit estimate of the link between costs and density. Capex for Western Power's transmission network appears in line with the trend estimate, a position that is supported by analysis of other capex ratios. Given the particular factors applying to South Australia and Victoria we would not offer an estimate based on the trend estimate in Figure 30. However, we would accept that the current level of capex in 2005 is justified when compared to the cost ratios exhibited by its peers.

6.8 Expenditure indicators for Western Power Transmission 2005

The cost analysis and performance comparisons presented in this section of the report have identified an annual revenue deficit for Western Power transmission ranging between $20 and $40M. An examination of the asset base, capital charges, opex, and capex has been undertaken to identify possible causes. We find that the relatively lower level of the asset base which reduced the level of capital charges available would account for around 40 per cent of the gap. However, opex and capex appear to be at acceptable levels and offer little explanation of the revenue shortfall.

We turned next to the allowed annual revenue requirement (AARR) and its building block components and noted a discrepancy between the sum of the building blocks and the revenue requirement. In 2005 the AARR was $89,451,491. However, the sum of the building blocks exceeded this revenue allowance by more than $10M (Table 11).

From the data in Figure 11 it is apparent that regulated annual revenues do not fully recover the building block allowances that have been used in this analysis.

Table 11: AARR and building blocks - 2005

	Revenue	Return on assets	Depreciation	Opex
Western Power Trans		45,368,832	21,160,250	32,835,239
AARR	$89,451,491			
Sum of building blocks	$99,370,321			
Difference	$9,918,830			

In this report, judgment as to the acceptability of each building block has been made on the basis that the amounts set down in Table 11 were recovered through the revenue allowance. It appears that this is not the case. Irrespective of where the shortfall occurs, Western Power transmission is being deprived of $10M annual revenues/expenditures under the current financial arrangements.

Accordingly, we must qualify our findings in relation to the appropriateness of the level of the building blocks. The capital charges and opex are only acceptable if they are fully funded by the underlying revenue stream. We are unable to assess where the shortfall is occurring but given the strong focus on maintaining the network in good condition it is most likely that it is being met from either reduced return on assets or depreciation. Traditionally, this has been the response to short term cost pressures, however experience suggests that it cannot offer a longer term solution.

With this caveat, and based on the analysis in the preceding sections we find that appropriate indicators for current revenue and expenditures for Western Power's transmission network in 2005 are as listed in Table 12.

Table 12: Western Power transmission: Revenue and expenditure indicators - 2005

Indicator	Estimated expenditure	Current expenditure	Change
Total revenue Range	$118M $117M - $119M	$89M	33%
Total revenue/MW	$44,296	$30,593	46%
Total revenue/km*kV	$166	$125	33%
Depreciation	Acceptable limit	$21,166,250	
Rate of return	Acceptable limit	$45,368,832	
Asset base	$683M	$586M	17%
Assets/km	$187,400	$160,330	16%
Opex/km	$9,253	$8,985	No change
Capex/km	$17,444	$17,444	No change

7 Transmission: Cost structure analysis – 2006

Devising forward-looking cost estimates is challenging since the future holds many unknowns, even in the relatively short time frame of five years. Again, as discussed in the section on distribution, the data for 2006 contains expenditure allowances from a mix of regulatory pricing periods. Variations in underlying risk free rates of return and other factors will produce outcomes that may vary over time. Table 13 details the mix of regulatory pricing periods:

Table 13: Regulatory pricing re-set dates

NSW	2005-2009
Victoria	2003-2008
Queensland	2003-2007
South Australia	2003-2008
Tasmania	2004-2009

It is also important to note that the ACCC has introduced changes to its approval process for capital expenditure, commencing with the NSW pricing decision in 2004. Capital expenditures are now approved in two tranches; an ex ante assessment largely limited to small to medium type investments, and contingent capex which relates to large augmentation projects which will only be approved ex post. The change in treatment may have some affect going forward upon the comparability of capex among the Australian transmission businesses.

The analysis in this section is restricted to an assessment of appropriate levels of operating and maintenance and capital expenditures.

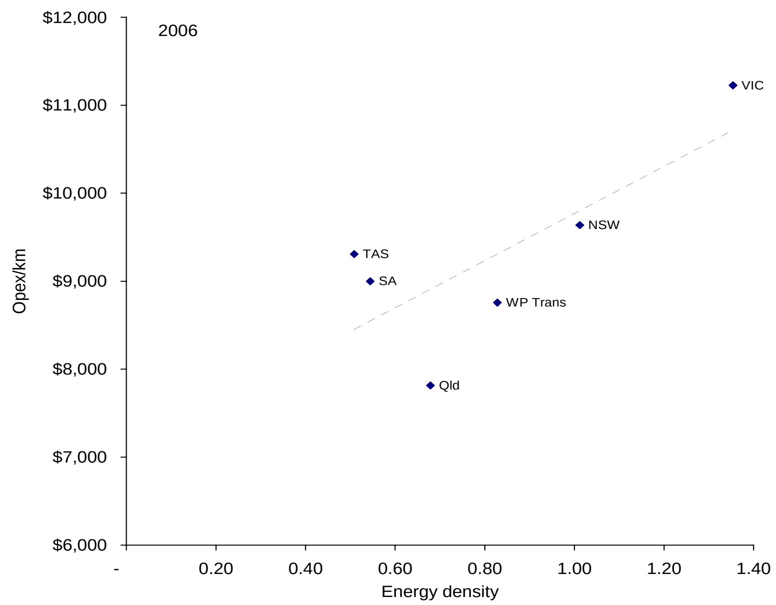
7.1 Operating and maintenance expenditures 2006

Moving forward to the expenditures projected for 2006, Figure 31 depicting opex/km and energy density exhibits the positive trend that is typical of the link between the two variables. Several points merit note.

First, the outlier position of Queensland. For some time it has been Powerlink's stated network management policy to minimise opex and over the longer term to refurbish or replace where necessary. In a network with rapid load growth this approach can be cost effective since the increasing demand could otherwise "strand" smaller plant or lower voltage lines. The distribution businesses had adopted a somewhat similar approach although the Queensland regulator in its recent pricing decision awarded significant expenditure increases to upgrade the networks which it believed had suffered from restricted expenditures.

The average opex level projected for Western Power transmission now appears more notably below trend as the higher expenditures for NSW arising from the recent pricing decision begin to work their way through.

Figure 31: Opex/km and energy density



The equation for the trend in Figure 31 and the estimate for Western Power transmission are:

Equation 5: Opex/km and energy density – 2006

Average opex/km = 2706.2x + 7078.8, R^2 60%

Estimated opex/km Western Power transmission	= $9,320
Planned opex/km	= $8,786
Difference per km: 6.5%	= $ 534
Estimated total opex 2006: 3655 km * $9320	= $34,064,000
Planned total opex 2006	= $32,000,000

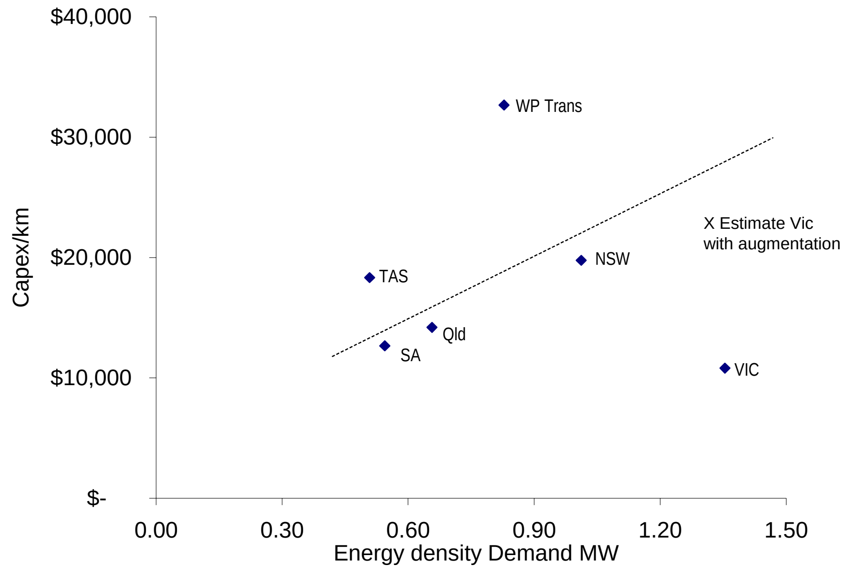
On the basis of Equation 5 we find that the projected opex for Western Power transmission is not excessive, and could be increased by at least $2M while still remaining in line with industry practice.

7.2 Capital expenditure - 2006

The data for the 2006 analysis is the annual average of the projected capex for the current pricing determination for Western Power, and of the second pricing determination for the other networks. In general, this covers the period out to 2009.

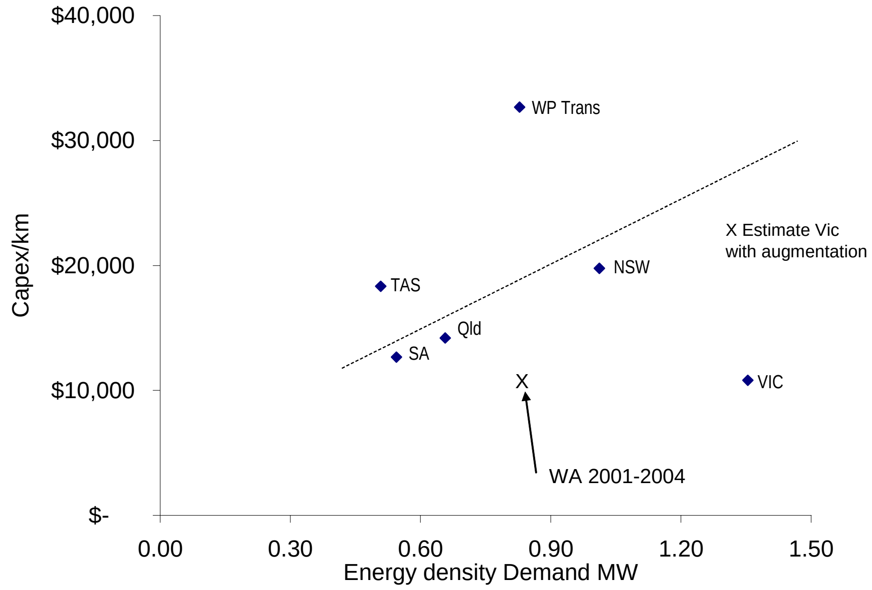
Western Power proposes to more than double capex in the three year period to 2009 relative to the five year period to 2005. This rate of increase is substantial but not without precedent in recent regulated pricing decisions. The impact on average capex expenditures is depicted in Figure 32 plotting capex/km against energy density.

Figure 32: Capex/km and energy density



Clearly, average capex projected from 2006 is above that of the average level for the other transmission networks. There are several factors, however, that could offer some explanation for this rate of increase. The first, and most significantly, is the under spend in the previous years (Figure 33).

Figure 33: Opex/km and energy density

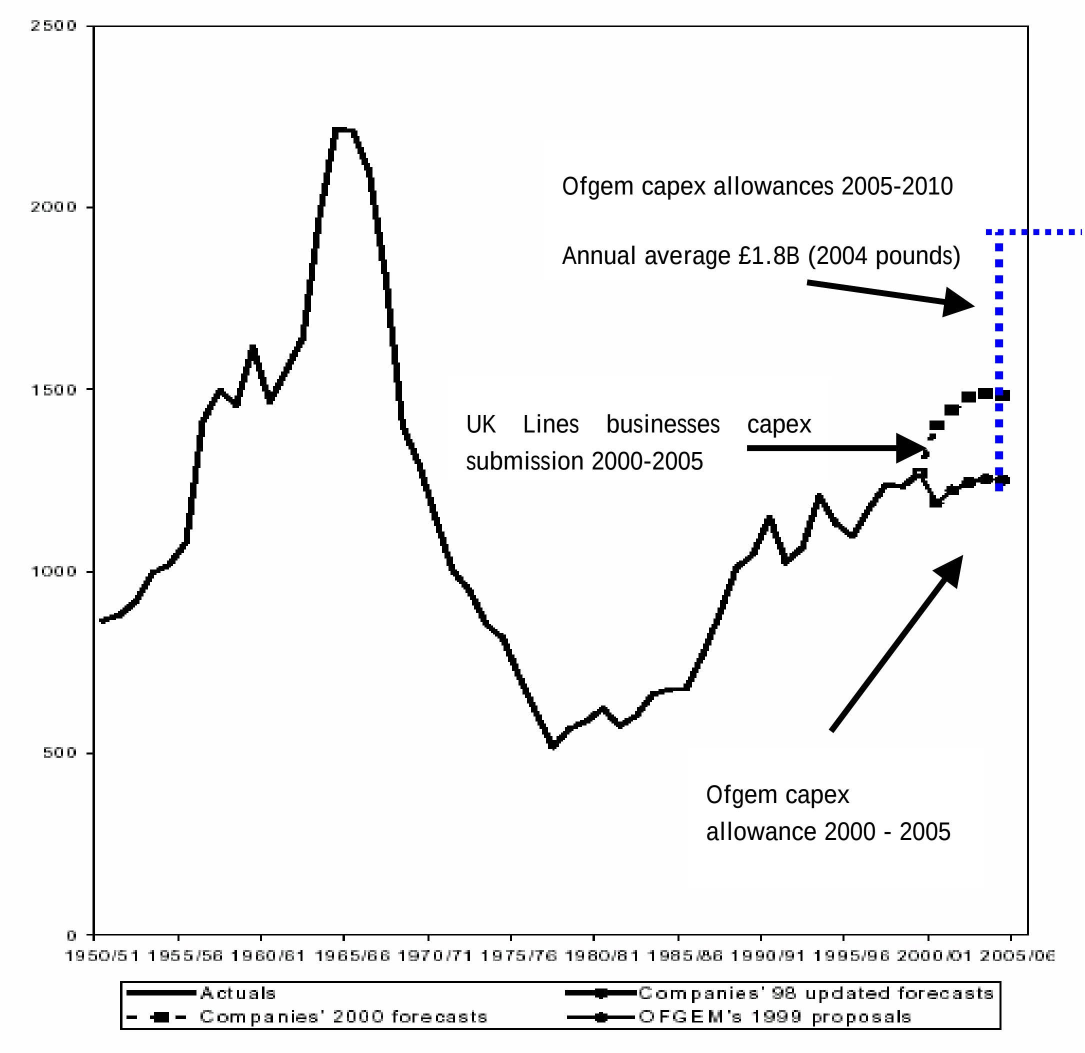


To illustrate the relatively lower level of capex for Western Power transmission in the period preceding 2006, Figure 33 also includes its average annual capex spend for period 2001 - 2004.

It would be likely that expenditures at this lower than average level over a protracted period would limit Western Power's ability to maintain its network to the standard of its peers. Our experience suggests that restricted expenditures ultimately lead to large step changes as businesses seek funds to meet not only the demands of load growth but also the necessary upgrade of the assets. The December 2004 increase in UK distribution network capex expenditures presents an excellent example of this catch-up.

Figure 34 plots annual average capex in real pounds sterling for the UK distributors for the 55 year period to 2006.

Figure 34: UK Distribution businesses: Annual Capital Expenditure (1997/8 prices, £Million)



Source: Ofgem, 2004 Pricing proposal – distribution networks

It shows the initial period of investment, the ensuing slowdown and the rebound from the mid-1970s as the initial investment required replacing. The slowdown in the growth of capex from the early 1990s and through to 2006 was recently unwound by a 55 per cent increase in real capital expenditure over the period to 2010 as the need to restore the UK's aging distribution networks became a high priority. Note, however, that the increase in 2004 only returns capex to the trend line, it does not "claw back" the estimated $30B "lost capex" in the period between 1990 and 2004.

As Figure 5, Section 3, depicting investment and replacement cycles clearly illustrated, electricity networks are now entering the stage where they require significant replacement investment. The level of concern at the financial impost this places on network businesses can best be measured by the size of the increases in capital expenditure allowed in recent regulatory pricing decisions (Table 13).

Table 13: Average annual Increase-capex allowances – recent regulatory pricing decisions

	Transmission	**Distribution**
NSW	2000-2004 - 2005-2009 43% increase	2000-2004 - 2005-2009 138% increase
Victoria	1999-2003 – 2004-2008 22% increase	2001-2005 - 2006-2010 36% increase
Qld	1999-2002 - 2003–2007 5.3% increase	2001-2005 - 2006-2010 140% increase
SA	2000-2003 - 2004 - 2008 22% increase	2001-2005 - 2006-2010 48% increase
Tas	2002-2003 - 2004 – 2009 19% increase	1999-2002 - 2003-2007 67% increase
UK		20001-2004 - 2005-2010 55% increase

Each network will, of course, will be influenced by its distinct operating environment including load growth, age of assets, generation construction, and other business conditions. Nevertheless, the increases listed in Table 13 provide adequate evidence that rising capex has become a feature of regulatory pricing determinations.

For Western Power, there remains also the issue of the allocation of costs between the transmission and sub-transmission networks. It is possible that the allocation proposed does not fully reflect the underlying cost drivers. We have raised this issue previously, and repeat our caution that some flexibility should be allowed in setting revenues to allow time for cost structures appropriate to these networks to emerge.

The trend line in Figure 32 has been influenced by both the relatively high position of Western Power and the atypical structure of the Victorian grid. We believe, that to a large extent, each outlier has offset the other. Accordingly, on the basis of the trend we estimate that an appropriate capex/km for Western Power transmission would be around $19,450 per km. With a range of +/- 10 % this would be $17,505 - $21,395. However, we believe that the need to “claw back” lost capex from preceeding years of lower expenditure could justify the additional capex projected.

7.3 Expenditure indicators 2006

The preceding section has assessed the appropriateness of the projected opex and capex expenditures for 2006 for the Western Power transmission network. It finds the opex requirement appropriate to a network of its configuration. There is potential to lift the annual expenditure by at least $2M and still remain comfortably in line with industry practice.

Capex is less straightforward. Clearly, the proposed expenditure represents a considerable step change from the past. However, with the emergence of the widely reported upswing in the replacement cycle, and set against a background of some years of below average expenditures, we could not reject this proposal as unjustifiable.

Based on standard industry practice as depicted in the preceding sections, we estimate that expenditure indicators, and an acceptable range, for the Western Power transmission only network are as listed in Table 14.

Table 14: Western Power transmission: Expenditure indicators - 2006

Indicator	Estimated expenditure	Current expenditure	Change
Opex/km Range + / - 10%	$9,320 $8,388 - $10,252	$8,786	6%
Capex/km Range + / - 10%	$19,450 $17,505 -$21,395 2006-2009	$12,263 2001-2005	58%

However, we recommend caution in respect of capex projections. The substantial realignments in capex budgets evidenced in other jurisdictions as the replacement cycle gathers pace and the simultaneous demands of the extended period of economic growth must cast serious doubt on the efficacy of “standard” practice for network investment. The unbundling of Western Power’s networks has added an extra dimension as management seeks to identify the cost allocations appropriate to each network business. We are of the view that further refinement of cost allocations may be required.

8 Sub-transmission

As discussed at the commencement of this report, the configuration of the Western Australian electricity networks is unusual in that it combines sub-transmission with transmission and not with distribution which is standard practice in Australia. It has therefore not been possible to directly compare the combined transmission networks with similar combinations. Sub-transmission was assessed only in combination with the distribution network. Though not dissimilar, differences at the margin in the underlying cost structures do not allow a simple summing of the transmission and sub-transmission outcomes.

While not optimal, we can draw a number of conclusions on the cost structure of sub-transmission.

8.1 Asset base

The asset base for sub-transmission is similar to transmission in that capital contributions, if any, play only a minor role. Accordingly the value of its assets is assumed to reflect closely the physical network. However, given the constraints of the structural arrangements it has not been possible to assess the appropriateness of the asset valuation with any degree of precision. The relative position of the combined network (transmission and subtransmission) in a number of the charts does indicate a level of assets that appears to be more closely aligned to its network configuration than that of transmission alone.

While the possibility of cost allocations must arise, the "average" performance of the combined network does not point to an excessive valuation in sub-transmission that could be transferred to transmission to lift it more in line with industry standards. Our qualified view is that the sub-transmission asset base is, at least, justified by its configuration, with potential for upward adjustment reflecting the identified undervaluation of the transmission assets.

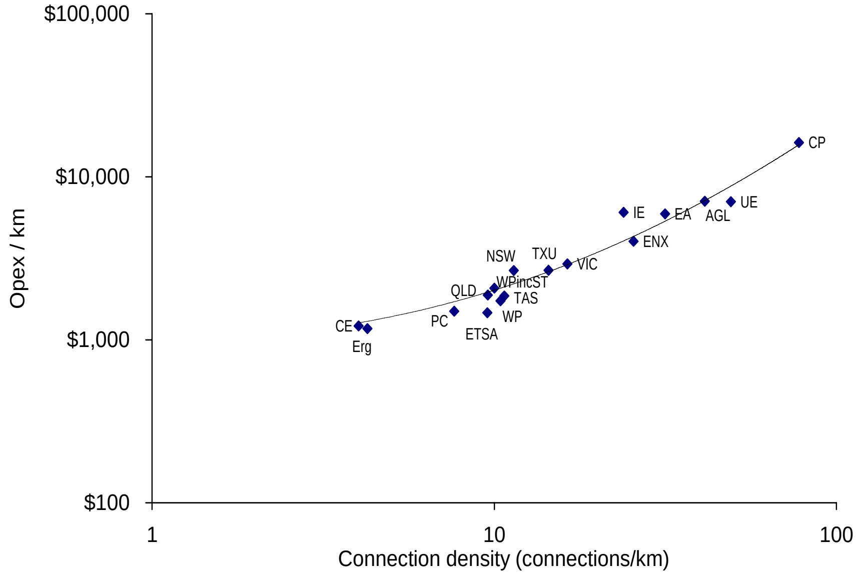
Any under-valuation that may exist would be expected to have implications for capital charges available to the business in the manner discussed in section 7.5.

8.2 Operating and maintenance expenditures

As a guide to the comparative level of opex for the sub-transmission network, Figure 34 depicts connection density and opex/km for the distribution networks, the most appropriate comparators for the sub-transmission network. The performance of the combined Western Power distribution + sub transmission network is in line with the industry average for a network with its connection density.

When considered in conjunction with the transmission analysis which indicated only moderate levels of expenditure, we are of the view that opex for the subtransmission network is justified by its operating environment. This finding applies equally to the 2005 and 2006 data.

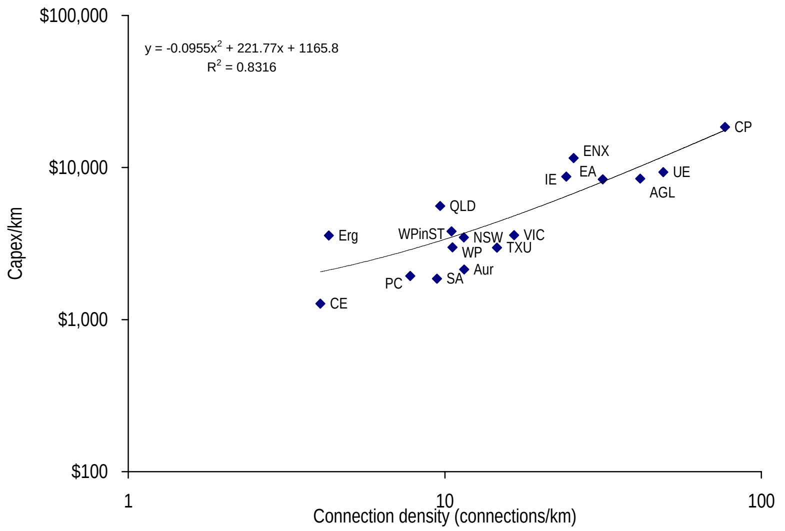
Figure 34: Opex/km and connection density: subtransmission – 2005



8.3 Capital expenditure

Figure 35 plots projected capex/km against connection density for the distribution (including sub-transmission) networks for 2006. The expenditure position of the combined Western Power networks is well in line with the industry trend. However, given timing differences in the pricing determinations (Table 6) we incline to the view that the trend line presents only a minimum level of expenditure.

Figure 35: Capex/km and connection density: subtransmission - 2006



The substantive capex increases recently awarded in NSW and Queensland, and detailed in Table 13, are evident in the above trend position of the businesses in these jurisdictions. As Western Australia shares an operating environment similar to that in Queensland with strong economic expansion and accompanying load growth we believe the trend estimate, $3,500, should be regarded only as the lower end of the target range for opex. The upper end of the range would set by the average for the state-wide Queensland network, at around $5,500 per km.

While this range may appear substantial it is best considered within the context of the unbundling of Western Power and the likely uncertainty over cost allocations.

8.4 Total revenues

Our brief analysis of the expenditures for sub-transmission finds that they are at least in line with industry standards. We do, however, find that there is a shortfall in revenues since the sum of the building blocks exceeds the recoverable revenues set by the AARR. Table 15 indicates that this deficit amounts to around $11M or 10 per cent of the AARR.

Western Power will only be able to maintain the level of expenditures appropriate to its network and pay a commercial return on funds invested, if it is allowed to recover the full capital and operating costs of its network.

Table 15: Subtransmission - AARR and building blocks - 2005

	Revenue	Return on assets	Depreciation	Opex
Western Power Sub-Trans		46,838,168	21,851,750	34,763,761
AARR	$92,348,509			
Sum of building blocks	$103,483,679			
Difference	$11,105,170			

9 Conclusion

9.1 Distribution

This report has undertaken a two-stage analysis of capex and opex for Western Power's distribution network. The first part has assessed the relative efficiency of existing expenditure allowances. The second part has analysed the potential efficiencies of the forward-looking expenditures for the period 2006-2010.

9.1.1 Expenditures 2005

The analysis finds that in 2005 Western Power distribution has a deficit of around $50M in its average annual revenue requirement when compared to similar networks. Several factors contribute to this outcome. One is the accounting treatment of capital contributions as revenue and not capital, which has reduced the level of depreciation available for refurbishment and replacement expenditure below levels comparable to other Australian networks by around one per cent of the asset base, estimated at $16M. It has also reduced the level of return on capital by around $18M. Unless changes are initiated in the accounting treatment, it is expected that revenues in 2006 will show a similar deficit.

It could also be that the recent increases in expenditures, which are at least in part a response to the growing pressures on the Western Australian electricity networks, may not have been fully accommodated by a commensurate increase in the regulated revenue allowance.

Detailed examination of Western Power's operating and maintenance and capital expenditures does not reveal any indications of inefficient cost or overspend. Opex and capex levels for the distribution network are justified by its specific operating environment and well within the range set by comparable networks.

9.1.2 Projected expenditures 2006

The analysis of the forward looking expenditures has been based on data for 2006, except for Victoria where 2006 data is not yet available. The cost categories examined have been limited to expenditures for operation and maintenance and capital.

Unprecedented increases in recent regulatory allowances for opex and capex had a significant influence on the rate of change in average level of expenditures between 2005 and 2006. Capex, in particular, was affected posting an average nine per cent rise. It is likely that this could rise further once the Victorian pricing determination is finalised.

One outcome of these changes has been greater variance around industry cost trends. While this has widened the range of appropriate cost outcomes, the underlying link between cost drivers and outcomes remains statistically sound. Cost levels for Western Power fall well within the estimated ranges and would be appropriate for a network subject to its operating conditions.

9.2 Transmission

The transmission network for Western Power includes sub-transmission in contrast to the Australian states where it forms part of the distribution network. Accordingly, the cost analysis is restricted to the transmission business.

9.2.1 Expenditures 2005

The analysis finds that Western Power transmission has a shortfall in its total regulated revenue for 2005 estimated in the range of $15-$35M. Several factors contribute to this result. In comparison with the industry trend, the asset base is estimated to be at least $97M below justifiable levels. In turn the lower level of capital charges associated with the existing asset value would account for around $11M of the estimated revenue shortfall.

We also find that the 2005 AARR does not allow full recovery of the sum of the building blocks, leaving a deficit of $11M. These two amounts offer a substantial contribution to the below average revenue performance of Western Power.

Detailed examination of opex and capex indicate a cost performance that aligns generally with the industry standard. Recent substantive increases in capex allowances in a number of other jurisdictions suggest that individual factors are playing a large role in individual decisions.

9.2.2 Expenditures 2006

This section examines only the projected opex and capex.

Moderate opex increases in 2006 in a number of the other jurisdictions, and little or no change in the opex projected for Western Power, results in it dropping below the industry trend. There is potential for increased expenditures.

To smooth volatile capex budgets, the 2006 analysis is based on five year averages. The projection for Western Power emerges well above the industry trend. Several factors offer explanation. First, there had been a period of below average spending which had eroded the reliability of the network. Next, there has been strong load growth as the economy expanded. Finally, unbundling of Western Power could have resulted in cost allocations that do not reflect adequately the three physical networks.

The environment in which individual networks operate is of particular importance in the consideration of incremental investment high voltage grids. Any factors specific to Western Power should be taken to account.

9.3 Subtransmission

The structural arrangements in Western Power do not allow an extensive quantitative analysis of sub-transmission. Our brief analysis of the expenditures however finds that they are at least in line with industry standards. Additionally, we have identified a shortfall in revenues which do not allow full recovery of total costs.

9.4 Conclusion

From the analysis we have undertaken for this report, we find, with a fair degree of probability, that the allocation of costs between the three networks may not fully reflect the costs appropriate to each type of network. Additionally, there is reason to believe that expensing and capitalisation policies in Western Australia might possibly vary from those in the other states.

This is not intended in any way to suggest that the expenditures for Western Power are more, or less, efficient than the other networks. Simply, the issue is whether the financial allocations adequately reflect the physical unbundling.