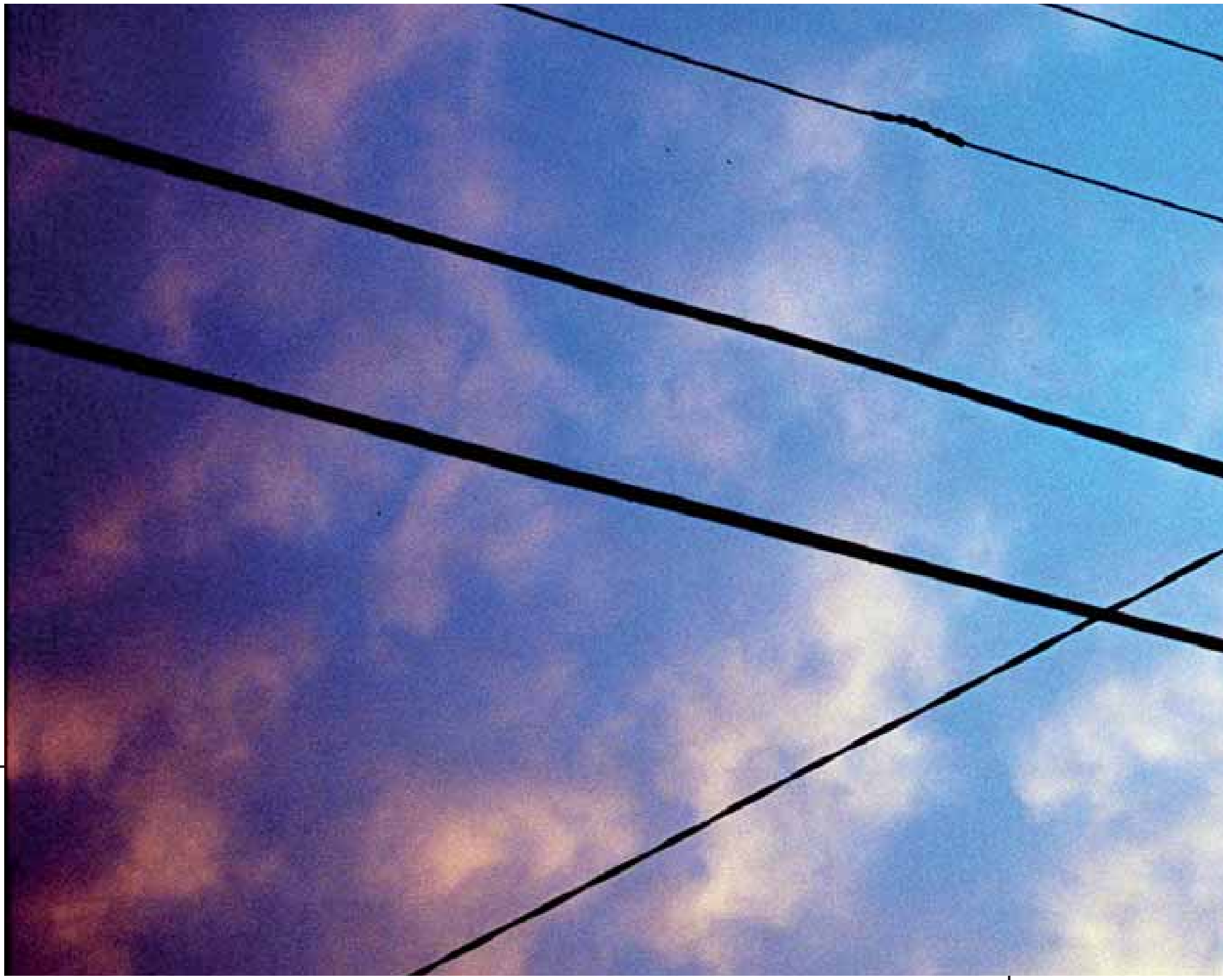


5 ELECTRICITY DISTRIBUTION


Quentin Jones (Fairfax Images)

Most electricity customers are located a long distance from generators. The electricity supply chain therefore requires networks to transport power from generators to customers. Chapter 4 provides a survey of high-voltage *transmission* networks that move electricity over long distances from generators to distribution networks in metropolitan and regional areas. This chapter focuses on the lower voltage *distribution* networks that move electricity from points along the transmission line to customers in cities, towns and regional communities.

5 ELECTRICITY DISTRIBUTION

The chapter considers:

> the role of the electricity distribution network sector
> the structure of the sector, including industry participants and ownership changes over time
> the economic regulation of the distribution network sector
> financial outcomes, including revenues and returns on assets
> new investment in distribution networks
> quality of service, including reliability and customer service performance.

There are a number of possible ways to present and analyse data on Australia's distribution networks. This chapter mostly adopts a convenient classification of the networks based on jurisdiction and ownership criteria. Other possible ways to analyse the data include by feeder—for example, a rural/urban classification. Section 5.6 includes some analysis based on a feeder classification.

While this chapter includes data that might enable performance comparisons to be made between networks, such analysis should note that geographical, environmental and other differences can affect relative performance. These factors are noted, where appropriate, in the chapter.

5.1 Role of distribution networks

Distribution networks move electricity from the transmission network to residential and business electricity customers.[1] A distribution network consists of low-voltage substations, transformers, switching equipment, monitoring and signalling equipment and the poles, underground channels and wires that carry electricity.

Transmission networks minimise the energy losses that occur in transporting electricity by moving it at high voltages along widely spaced lines between high towers. This configuration would not be cost effective in distribution, and it would raise aesthetic and environmental issues. Nor can high-voltage electricity be safely consumed in homes and businesses. It is therefore necessary to step electricity down to lower voltages when it enters a distribution network. Voltage levels vary in different parts of a distribution network, but most customers in the National Electricity Market (NEM) require delivery at around 230–240 volts.

While transmission networks run for long distances on high towers between substations, distribution networks consist of smaller poles and wires that crisscross customer areas and connect to every customer. This tends to make distribution networks longer in length than transmission networks. The total length of distribution infrastructure in the NEM (700 000 km) is around 16 times greater than the total length of transmission infrastructure (42 000 km).

In Australia, electricity distributors provide the infrastructure to transport electricity to household and business customers, but do not sell electricity. Instead, retailers bundle electricity generation with transmission and distribution services and sell them as a package. In some jurisdictions, there is common ownership of distributors and retailers, which are 'ring-fenced' or operationally separated from one another.

The contribution of distribution costs to final retail prices varies between jurisdictions, customer types and locations. Data on the underlying composition of retail prices is not widely available. A 2002 report for the Victorian Government estimated that transmission and distribution jointly account for about 44 per cent of a typical residential electricity bill.[2] The Essential Services Commission of South Australia (ESCOSA) reported a similar estimate in 2004.[3] The Essential Services Commission of Victoria (ESC) reported in 2004 that distribution can account for 30 to 50 per cent of retail prices, depending on customer type, energy consumption, location and other factors.[4]

5.2 Australia's distribution networks

In Australia, there are distribution networks in all states and territories, serving population centres and industry in cities, towns and regional areas. This section provides an overview of network ownership, geography and size. Table 5.1 provides a full listing of the networks.

1 There are exceptions. For example, some large businesses such as aluminium smelters can bypass the distribution network and source electricity directly from the transmission network. Conversely, embedded generators have no physical connection with the transmission network and dispatch electricity directly into a distribution network.

2 Charles Rivers Associates, *Electricity and gas standing offers and deemed contracts (2003)*, December 2002.

3 ESCOSA, *Inquiry into retail electricity price path: Discussion paper*, September 2004, p. 27.

4 ESC, *Electricity distribution price review 2006-10*, Issues paper, December 2004, p. 5.


John Donegan (Fairfax Images)

Ownership

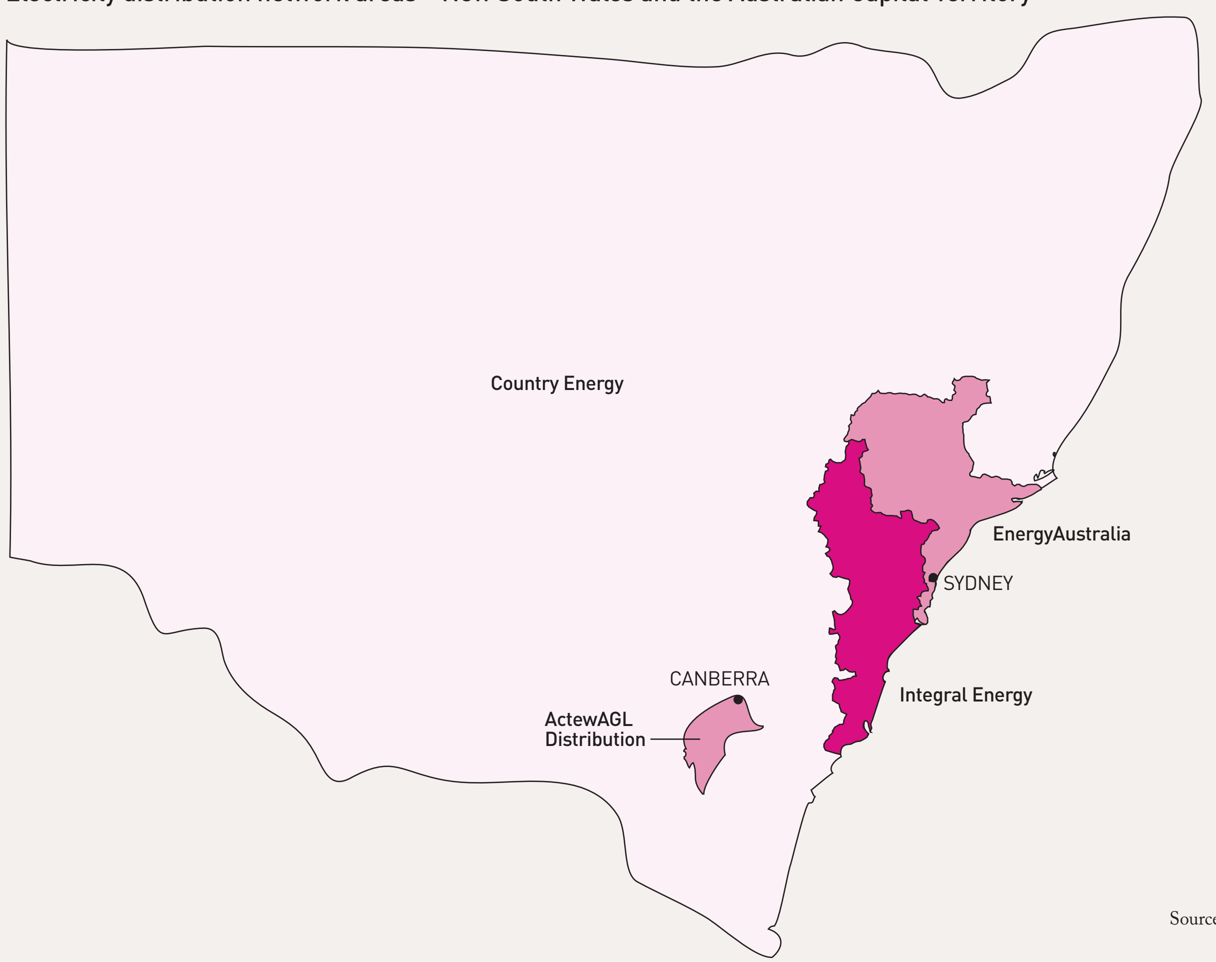
There are 13 major electricity distribution networks in the NEM (table 5.1). Of these, six (in Victoria and South Australia) are privately owned or leased, one has combined government and private ownership (the Australian Capital Territory) and six (in other jurisdictions) are government owned.

Historically, government utilities ran the entire electricity supply chain in all states and territories. In the 1990s, governments began to carve out the generation, transmission, distribution and retail segments into stand-alone businesses. Generation and retail were opened up to competition. This was not feasible in transmission and distribution, where economies of scale make it more efficient to have a regulated monopoly provider of services rather than competing networks.

New South Wales, Victoria and Queensland have multiple major networks, each of which is a monopoly provider in a designated area of the state. Figures 5.1a–c provide illustrative maps for New South Wales, Victoria and Queensland. In the other jurisdictions there is one major provider of network services. There are also small regional networks with separate ownership in some jurisdictions.

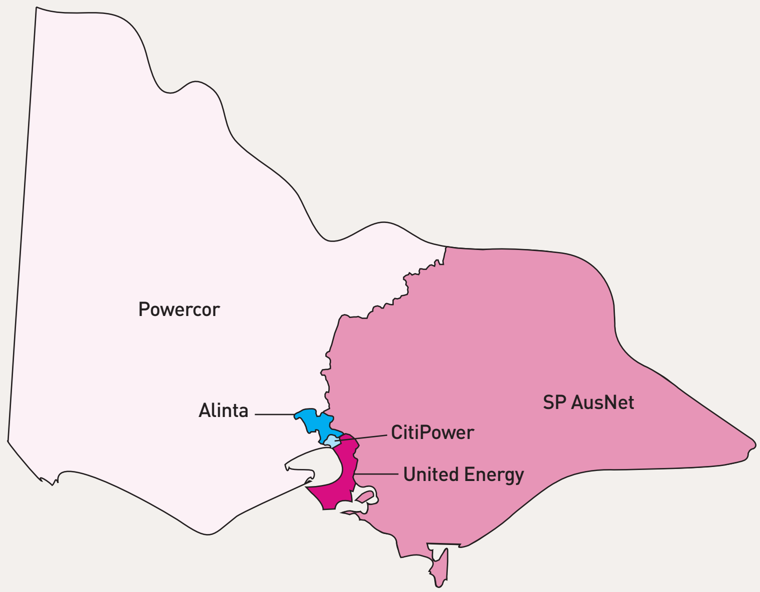
Figure 5.1a

Electricity distribution network areas—New South Wales and the Australian Capital Territory



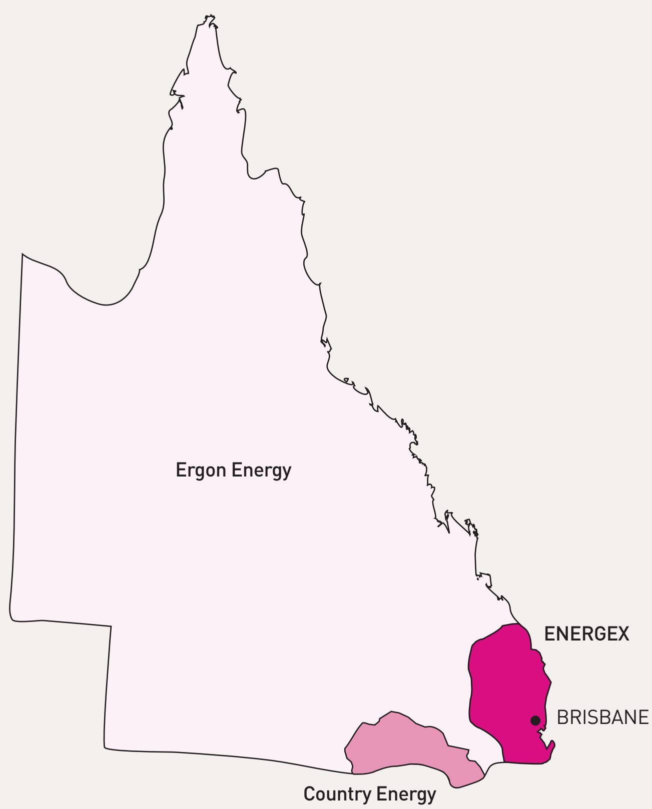
Source: IPART

Figure 5.1b
Electricity distribution network areas—Victoria



Source: ESC

Figure 5.1c
Electricity distribution network areas—Queensland



Source: QCA

Table 5.1 sets out current ownership arrangements for the networks. Privatisation in Victoria and South Australia in the 1990s led to considerable ownership diversity, but merger and acquisition activity has since reduced the number of private sector players to three—Cheung Kong Infrastructure/Spark, SP AusNet/Singapore Power and Alinta/Diversified Utility and Energy Trust (DUET).

Table 5.1 Distribution networks

NETWORK	LOCATION	LINE LENGTH (KM)	CUSTOMER NUMBERS	RAB ($ MILLION)	REGULATOR	OWNER
NEM REGIONS						
Alinta (Solaris)	Vic	5579	286 085	589	ESC	Alinta
CitiPower	Vic	6488	286 107	1 022	ESC	Cheung Kong Infrastructure Holdings Limited and Hongkong Electric Holdings 51%; Spark Infrastructure 49%
Powercor	Vic	80 577	644 113	1 671	ESC	Cheung Kong Infrastructure Holdings Limited and Hongkong Electric Holdings 51%; Spark Infrastructure 49%
SP AusNet	Vic	29 397	573 766	1 363	ESC	Singapore Power International 51%
United Energy	Vic	12 308	609 585	1 229	ESC	Alinta 34%; DUET 66%
ETSA Utilities	SA	80 644	781 881	2 468	ESCOSA	Cheung Kong Infrastructure Holdings Limited and Hongkong Electric Holdings 51%; Spark Infrastructure 49%
EnergyAustralia	NSW	47 144	1 539 030	4 116	IPART	NSW Government
Integral Energy	NSW	33 863	822 446	2 283	IPART	NSW Government
Country Energy	NSW	182 023	734 071	2 375	IPART	NSW Government
ActewAGL	ACT	4623	146 556	528	ICRC	ACTEW Distribution Limited 50% (ACT Government); Alinta 50%
ENERGEX	Qld	48 115	1 217 193	5 023	QCA	Qld Government
Ergon Energy	Qld	142 793	736 710	4 690	QCA	Qld Government
Aurora Energy	Tas	24 400	259 600	687	OTTER	Tas Government
NON-NEM REGIONS						
Western Power	WA	69 083		1 595	ERA	WA Government
Power and Water	NT	7869		440	UC	NT Government

Notes:

1. ESC (Essential Services Commission of Victoria); ESCOSA (Essential Services Commission of South Australia); IPART (Independent Pricing and Regulatory Tribunal); ICRC (Independent Competition and Regulatory Commission); QCA (Queensland Competition Authority); OTTER (Office of the Tasmanian Energy Regulator); ERA (Economic Regulation Authority of Western Australia); UC (Northern Territory Utilities Commission).
2. RAB (regulated asset base) measurement: ESC ($2004 as of 2006–07); ESCOSA (Dec $2004 as of 2006–07); IPART (nominal as of 1 July 2004); ICRC (nominal as of 2005–06); QCA (nominal as of 2005-06); OTTER (nominal as of 30 June 2003); ERA (nominal as of 30 June 2006); UC (includes both transmission and distribution as of February 2004).
3. A Babcock & Brown/Singapore Power consortium acquired Alinta under a conditional agreement in May 2007.

The Victorian Government initially split its distribution sector into five separate businesses: CitiPower, Solaris and United Energy which mainly serve metropolitan Melbourne; and Eastern Energy and Powercor which serve the rest of Victoria (figure 5.1b). In 1995, the networks were sold to various private interests, but there has since been considerable consolidation:

- Cheung Kong Infrastructure/Hong Kong Electric Holdings, members of the Cheung Kong group, acquired Powercor in 2000 and CitiPower in 2002. Cheung Kong floated 49 per cent of its Victoria/South Australia distribution assets as Spark Infrastructure in 2005.
- Singapore Power acquired the Eastern Energy network from TXU in 2004, following its acquisition of the Victorian transmission network in 2000. Singapore Power sold 49 per cent of its Australian electricity assets through a partial float of SP AusNet in November 2005.
- Alinta and DUET, which is managed by AMP Henderson and Macquarie Bank, acquired the United Energy network in 2003. United Energy is 34 per cent owned by Alinta, which operates and manages the network. DUET holds a 66 per cent equity interest. Alinta also acquired the Solaris network from AGL in 2006.
- A Babcock & Brown/Singapore Power consortium acquired Alinta under a conditional agreement in May 2007.

There has also been a separation between the ownership and operation of some networks. For example, while DUET has a majority equity interest in United Energy, the minority owner—Alinta—operates and manages the network.

In South Australia, the government leased the single distribution network business (ETSA Utilities) to the Cheung Kong group in January 2000 under a 200-year lease. In 2005, Cheung Kong floated 49 per cent of its equity as Spark Infrastructure.

The other NEM jurisdictions restructured their distribution networks but retained government ownership:

- New South Wales restructured 25 electricity distribution businesses into six government owned corporations in the 1990s. Further consolidation of regional networks reduced this number to three —EnergyAustralia, Integral Energy and Country Energy (figure 5.1a). The most recent change involved Australian Inland, which merged with Country Energy in 2005.
- Queensland consolidated seven government-owned electricity distributors into two in the late 1990s —ENERGEX and Ergon Energy (figure 5.1c).
- The government owned Aurora Energy is the sole electricity distributor in Tasmania.
- The Australian Capital Territory electricity distribution network is jointly owned by the Australian Capital Territory Government and Alinta.[5]

In some jurisdictions there are ownership linkages between electricity distribution and other parts of the energy sector (table 5.2). New South Wales and Tasmania have common ownership in electricity distribution and retailing, with ring-fencing arrangements for operational separation. Victoria completed its separation of the sectors in 2006 when Alinta acquired AGL's networks assets. Queensland privatised most of its energy retail sector in 2006–07, which largely separated it from distribution.[6]

A number of electricity distributors also provide gas transportation services. The most significant is Alinta/DUET, which owns electricity and gas distribution infrastructure in Victoria, gas distribution in Western Australia and several gas transmission pipelines. Cheung Kong Infrastructure owns electricity distribution assets in Victoria and South Australia, and is a minority owner of Envestra—which distributes gas in a number of jurisdictions, including Victoria, South Australia and Queensland. SP AusNet has interests in electricity transmission and distribution and gas distribution. The Queensland Government traditionally owned electricity and gas distribution networks, but privatised its gas assets in 2006.

5 For information on Western Australia and the Northern Territory see chapter 7.
6 The Queensland Government owned distributor Ergon Energy is also an energy retailer to 600 000 unprofitable customers.

Scale of the networks

Table 5.1 notes the size of Australia's distribution networks as reflected by their line length and regulated asset base (RAB). The RAB is an asset valuation that regulators apply in conjunction with rates of return to set the returns on capital for infrastructure owners.

Figure 5.2 compares the RABs of distribution networks in the NEM. ENERGEX and Ergon Energy (Queensland) and EnergyAustralia (New South Wales) have the largest RABs, each exceeding $4 billion. The Queensland networks make up the largest combined statewide RAB (around $9.7 billion), followed by New South Wales ($8.8 billion), Victoria ($5.8 billion) and South Australia ($2.5 billion). The RABs of the Tasmanian and the Australian Capital Territory networks are relatively small. NEM-wide, the combined RABs of distribution networks is around $27 billion, more than double the valuation for transmission infrastructure.

Many factors can affect RAB value, including the basis of original valuation, network investment, the age of a network, geographical scale, the distances required to transport electricity from transmission connection points to demand centres, population dispersion and forecast demand profiles.

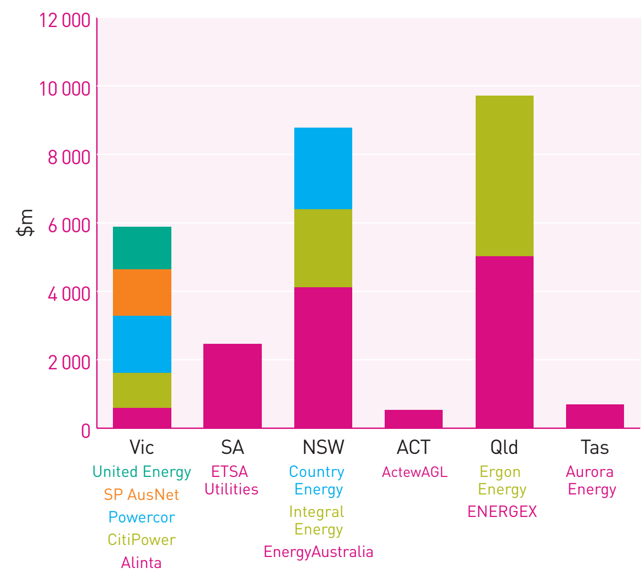
5.3 Economic regulation of distribution services

Electricity networks are highly capital intensive and incur relatively low operating costs. This gives rise to economies of scale that make it more efficient to have one provider of network services in a geographical area than to have competing providers. Economists describe this situation as a natural monopoly. As noted in section 4.3, independent regulation of natural monopolies can manage the risk of the exercise of market power.

Table 5.2 Ownership linkages between electricity distribution and other energy market segments

OWNERSHIP LINKAGE	DISTRIBUTION BUSINESS
Electricity distribution and transmission	SP AusNet (Vic); EnergyAustralia (NSW)
Electricity distribution and retail	EnergyAustralia, Integral Energy and Country Energy (NSW); Aurora Energy (Tas); Ergon Energy (Qld)
Electricity distribution and gas transportation	Alinta/DUET; Cheung Kong Infrastructure; SP AusNet

Figure 5.2
Regulated asset bases of distribution networks by jurisdiction as of 2006



Note: See note 2, table 5.1

Sources: Regulatory determinations of ESC (Vic); IPART (NSW); QCA (Qld); ESCOSA (SA); OTTER (Tas); and ICRC (ACT).

CHAPTER 5 ELECTRICITY DISTRIBUTION

State-based regulatory agencies are currently responsible for the economic regulation of distribution networks. However, governments in the NEM have agreed to transfer these responsibilities to the Australian Energy Regulator (AER) from 2008. The regulation of distribution networks in Western Australia and the Northern Territory will remain under state and territory jurisdiction.

The National Electricity Rules (NER) set out the framework for regulating distribution networks. The NER require the use of an incentive-based regulatory scheme but allow each jurisdictional regulator to choose the form of regulation. The options allowed under the NER include a revenue cap, a weighted average price cap or a combination of the two. In addition, some jurisdictional regulators impose local regulatory frameworks as a condition of licensing arrangements for distribution businesses. Regulatory frameworks that some jurisdictional regulators impose include revenue yield models that control the average revenue per unit sold, based on volumes or revenue drivers. In South Australia, an electricity pricing order sets some elements of the regulatory framework.

In essence, each approach involves the setting of a ceiling on the revenues or prices that a distribution business is allowed to earn or charge. As table 5.3 illustrates, the NEM jurisdictions use a range of approaches.

Most jurisdictions apply a building-block approach to determine the revenue or price ceiling. The building blocks factor in a network's operating costs, asset depreciation costs, taxation liabilities and a commercial return on capital. The setting of these elements has regard to various factors, including projected demand growth, price stability, the potential for efficiency gains in cost and capital expenditure management, service standards and the provision of a fair and reasonable risk-adjusted rate of return on efficient investment.

Table 5.3 Forms of incentive regulation in the NEM

FORM OF REGULATION	HOW IT WORKS	REGULATOR	NETWORK(S)
Weighted average price cap	Sets a ceiling on a weighted average of distribution tariffs (prices). The distribution business is free to adjust its individual tariffs as long as the weighted average remains within the ceiling. There is no cap on the total revenue a distribution business may earn. Revenues can vary depending on tariff structures and the volume of electricity sales.	Essential Services Commission (Vic) Independent Pricing and Regulatory Tribunal (NSW)	Alinta CitiPower Powercor SP AusNet United Energy EnergyAustralia Integral Energy Country Energy
Revenue cap	Sets the maximum revenue a distribution network may earn during a regulatory period. It effectively caps total earnings. This mirrors the approach used to regulate transmission networks. The distribution business is free to determine individual tariffs such that total revenues do not exceed the cap.	Queensland Competition Authority (Qld) Independent Competition and Regulatory Commission (ACT) Office of the Tasmanian Energy Regulator (Tas)	ENERGEX Ergon Energy ActewAGL Aurora Energy
Revenue yield (average revenue control)	Links the amount of revenue a distribution business may earn to the volume of electricity sold. Total revenues are not capped and may vary in proportion to the volume of electricity sales. The distribution business is free to determine individual tariffs—subject to tariff principles and side constraints—such that total revenues do not exceed the average.	Essential Services Commission of South Australia (SA)	ETSA Utilities

There are also variations in the treatment of specific components of the building block and the incentive schemes attached to some elements of the blocks. For example:

- most jurisdictions 'lock in and roll forward' although in 2005 the Queensland regulator revalued the regulated asset bases of ENERGEX and Ergon Energy, using a depreciated optimised replacement cost method[7]
- in determining a return on capital, there are differences in the treatment of taxation between jurisdictions
- jurisdictions apply different types of incentive mechanisms that encourage distribution businesses to manage their operating and capital expenditure efficiently
- some jurisdictions conduct an ex post check of the prudency of past investment when determining the amount of capital expenditure to be rolled into the RAB
- Victoria, South Australia and Tasmania apply financial incentive schemes for distribution businesses to maintain—and improve—efficient service standards over time. New South Wales has a paper trial in progress. Queensland does not currently operate such a scheme.

In applying any of the forms of regulation in table 5.3, a regulator must forecast the revenue requirement of a distribution business over the regulatory period. In turn, this must factor in investment forecasts and the operating expenditure allowances that a benchmark distribution business would require if operating efficiently. The aim is not to encourage a distribution network to fully spend its forecast allowances, but to provide incentives for it to reduce costs through efficient management—that is, to beat the allowance. However, as discussed in section 5.6, these incentives must be balanced against a service standards regime to ensure underspending does not occur at the expense of a reliable and safe distribution network.

Revenues

Figures 5.3a and 5.3b chart the forecast revenue allowances for distribution networks in the NEM, as determined by the jurisdictional regulators. The data is deflated to remove the effects of inflation. Various factors affect the forecasts, including differences in scale and market conditions and differences in regulatory approach.

Allowed revenues are tending to rise over time as the underlying asset base expands to meet rising demand. The combined revenue of the NEM's 13 major distribution networks was forecast at around \$5150 million in 2005–06 (in \$2006), with projected real growth of around 12.5 per cent in the two years to 2007–08. Revenue growth has been strong for the New South Wales and Queensland networks, but has generally been flatter in Victoria and South Australia.

Return on assets

Jurisdictional regulators publish annual regulatory and performance reports that include indicators of the profitability and efficiency of distribution businesses. A commonly used financial indicator to assess the performance of a business is the return on assets.

The return on assets is calculated as operating profits (net profit before interest and taxation) as a percentage of the average RAB. Figure 5.4 sets out the return on assets for distribution networks where data is available. Over the last five years, the government owned distribution businesses in New South Wales, Queensland and Tasmania have achieved returns ranging between 4 and 10 per cent. The privately owned distribution businesses in Victoria and South Australia tended to yield returns of about 8 to 12 per cent.

A variety of factors can affect performance in this area. These might include differences in the demand and cost environments faced by each business and variances in demand and costs outcomes compared to those forecasted in the regulatory process.

7 Queensland Competition Authority, *Final determination: Regulation of electricity distribution*, April 2005, p. 57.

Figure 5.3a

Allowed revenues — Victoria, South Australia and Tasmania

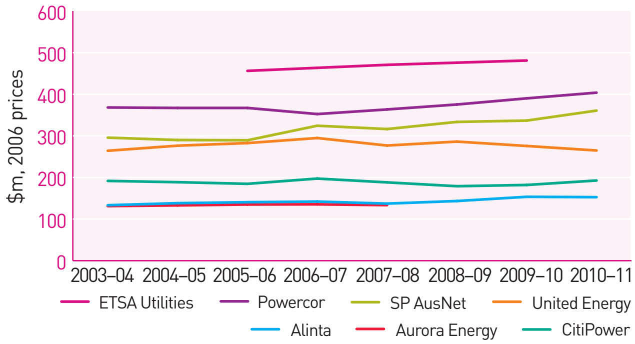
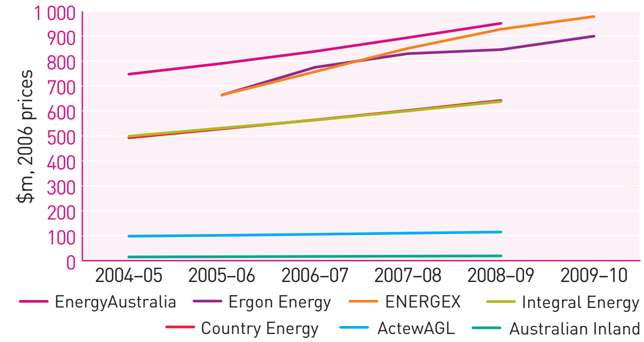


Figure 5.3b

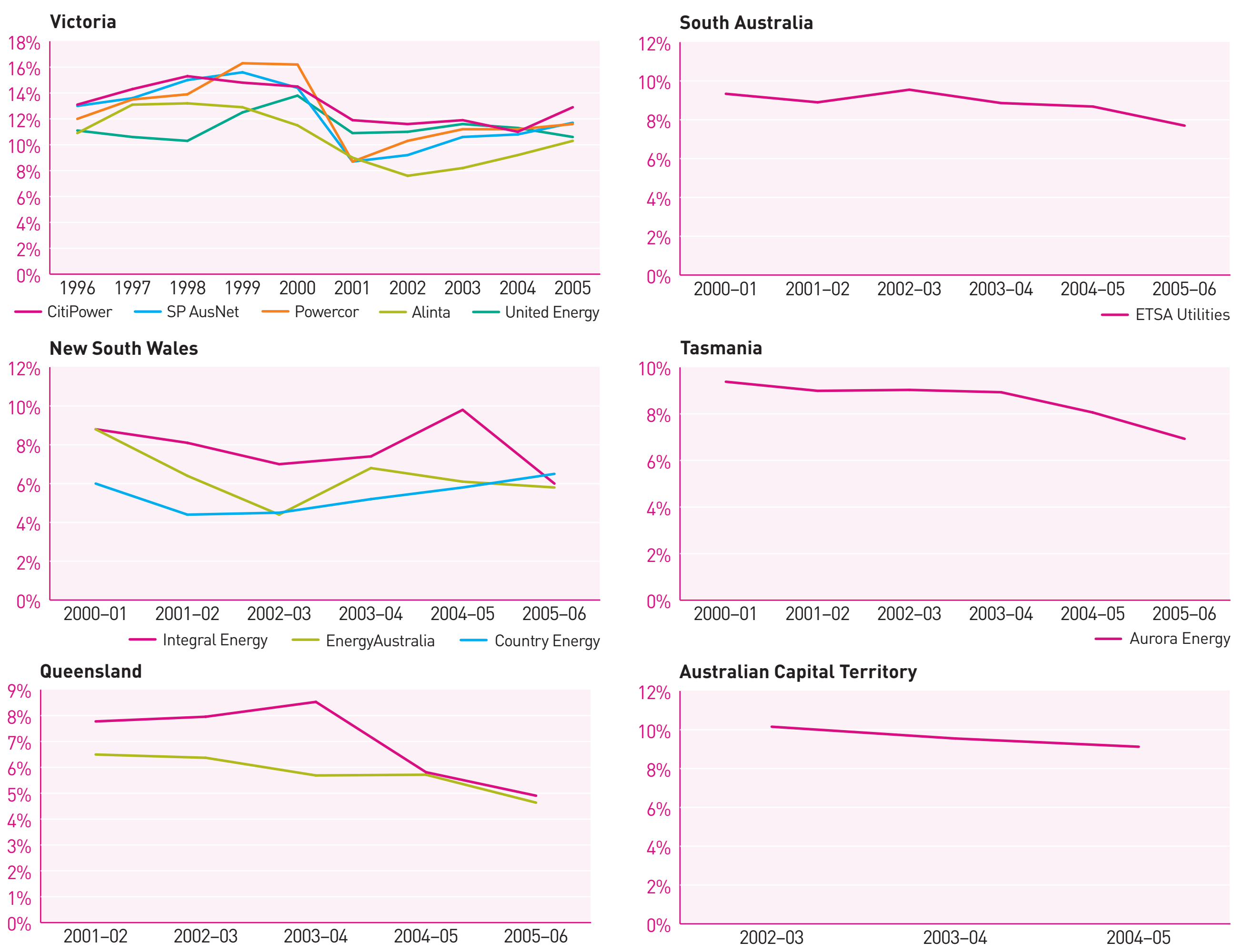
Allowed revenues — New South Wales, the Australian Capital Territory and Queensland



Source: Regulatory determinations of ESC (Vic); IPART (NSW); QCA (Qld); ESCOSA (SA); OTTER (Tas); and ICRC (ACT).

Figure 5.4

Return on assets for distribution networks in the NEM



Sources: Regulatory determinations and distribution network performance reports published by ESC (Vic); IPART (NSW); QCA (Qld); ESCOSA (SA); OTTER (Tas); and ICRC (ACT).

5.4 Distribution investment

New investment in distribution infrastructure is needed to maintain or improve network performance over time. Investment covers network augmentations (expansions) to meet rising demand and the replacement of depreciated and ageing assets. Some investment is driven by regulatory requirements on matters such as network reliability.

Figures 5.5 and 5.6 chart real investment in distribution infrastructure in the NEM, based on actual data where available, and forecast data for other years. Figure 5.5 charts investment by network business, while figure 5.6 charts aggregate outcomes for each jurisdiction.

The forecast data relates to investment proposed by a distribution business that the regulator has approved as efficient at the beginning of the regulatory period. At the end of the regulatory period, the RAB is adjusted to reflect actual investment that has occurred over the period. In some jurisdictions, actual expenditure will be subject to a prudency test before qualifying for inclusion in the RAB.

There is some volatility in the data, which reflects timing differences between the commissioning and completion of some projects. More generally, the network businesses have some flexibility to manage and reprioritise their capital expenditure over the five-year regulatory period. Further, there is some lumpiness in distribution investment because of the one-off nature of some capital programs—although investment tends to exhibit smoother trends in distribution than in transmission. The transition from actual to forecast data may also cause some volatility in the data points. These factors suggest that the analysis of investment data should focus on longer term trends rather than short-term fluctuations.

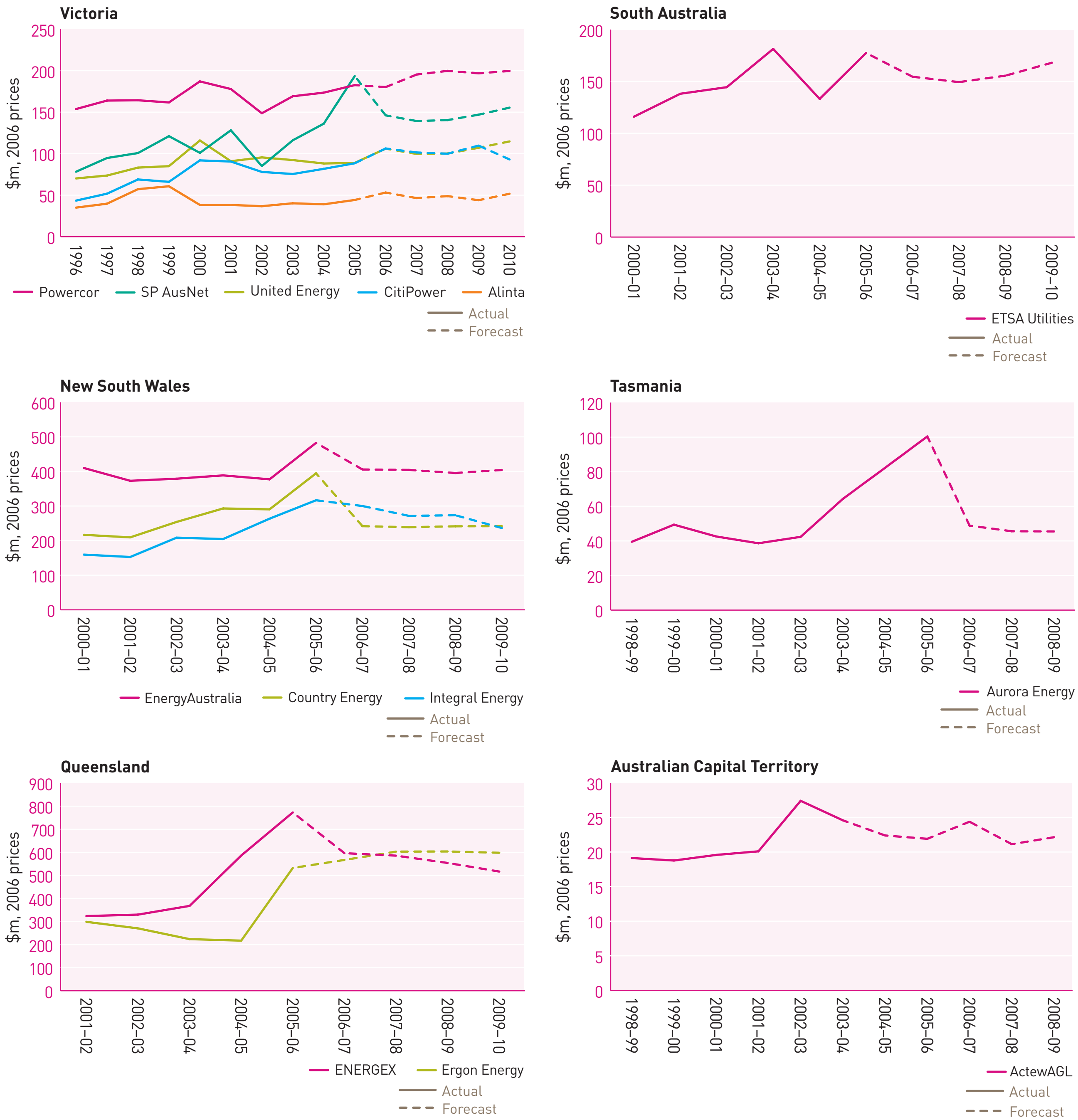
The charts indicate that there has been significant investment in distribution infrastructure since the commencement of the NEM. In total, real investment has risen from around $2080 million in 2001–02 to around $3400 million in 2005–06. This represents average annual real growth of around 13 per cent. Real investment growth is forecast to ease in the latter part of the decade.

At the jurisdiction level:

- investment in New South Wales rose by around 62 per cent between 2001–02 and 2005–06 to around $1190 million—equal to around 13.6 per cent of the statewide RAB
- investment in Queensland rose by around 110 per cent between 2001–02 and 2005–06 to over $1300 million—equal to around 13.4 per cent of the statewide RAB
- investment in Victoria rose by around 13.7 per cent between 2001–02 and 2005–06 to around $600 million—equal to around 10.2 per cent of the statewide RAB
- investment in South Australia rose by around 28.5 per cent between 2001–02 and 2005–06 to around $180 million—equal to around 7.2 per cent of the statewide RAB
- investment in Tasmania rose by around 160 per cent between 2001–02 and 2005–06 to around $100 million—equal to around 14.6 per cent of the statewide RAB.

The different outcomes between jurisdictions reflect a range of variables, including differences in scale and investment drivers, such as the age of the networks and demand projections. Differences in regulatory requirements on matters such as network reliability also affect investment outcomes.

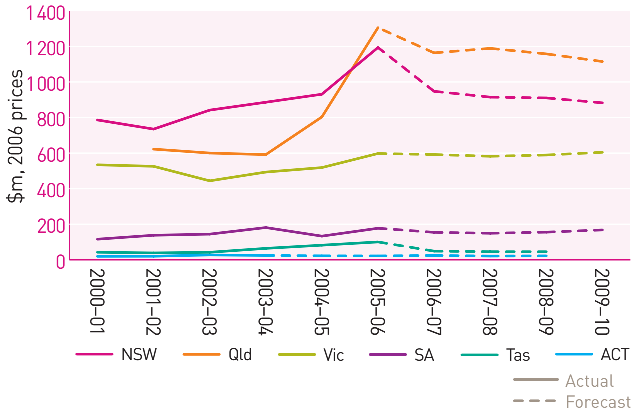
Figure 5.5
Actual and forecast capital expenditures



Source: Regulatory determinations and distribution network performance reports published by ESC (Vic); IPART (NSW); QCA (Qld); ESCOSA (SA); OTTER (Tas); and ICRC (ACT).

Figure 5.6

Aggregate distribution capital expenditure by jurisdiction



Source: Regulatory determinations and distribution network performance reports published by ESC (Vic); IPART (NSW); QCA (Qld); ESCOSA (SA); OTTER (Tas); and ICRC (ACT).

5.5 Operating and maintenance expenditure

As in the regulation of transmission businesses, regulators provide an allowance for distribution businesses to cover an efficient level of operating and maintenance expenditure over the regulatory period. A target (forecast) level of expenditure is set and an incentive scheme encourages the distribution business to reduce its spending through efficient operating practices. The schemes vary between jurisdictions, but generally allow the business to retain some or all of its underspending against target in the current regulatory period. Some jurisdictions also apply a service standards incentive scheme to ensure that cost savings are not achieved at the expense of network performance (section 5.6).

The jurisdictional regulators publish comparisons of target and actual levels of expenditure. Figure 5.7 charts the percentage variances for each jurisdiction. A positive variance indicates that actual expenditure exceeded target in that year—that is, the distribution business overspent. Similarly, a negative variance indicates that a distribution business underspent against target. A trend of negative variances over time may suggest a positive response to efficiency incentives. Conversely, it would be possible that the original targets were too generous. More generally, care should be taken in interpreting year-to-year changes in operating expenditure. As the network businesses have some flexibility to manage their expenditure over the regulatory period, timing considerations may affect the data. This suggests that analysis should focus on longer term trends.

Figure 5.7 indicates that most of the Victorian networks and ENERGEX (Queensland) underspent against their forecast allowances for most or all of the charted period. The New South Wales networks and Ergon Energy (Queensland) have tended to overspend against target, but each recorded sharply improved performance in 2005–06. ETSA Utilities has had varied performance against target, but with sharp improvement since 2003–04.

5.6 Service quality and reliability

Electricity distribution networks are monopolies that face little risk of losing customers if they provide poor quality service. In addition, regulatory incentive schemes for efficient cost management might encourage a business to sacrifice service quality to reduce costs. In recognition of these risks, governments and regulators monitor the performance of distribution businesses to ensure they provide acceptable levels of service. Some jurisdictions also provide financial incentives to encourage distribution businesses to meet target levels of service.

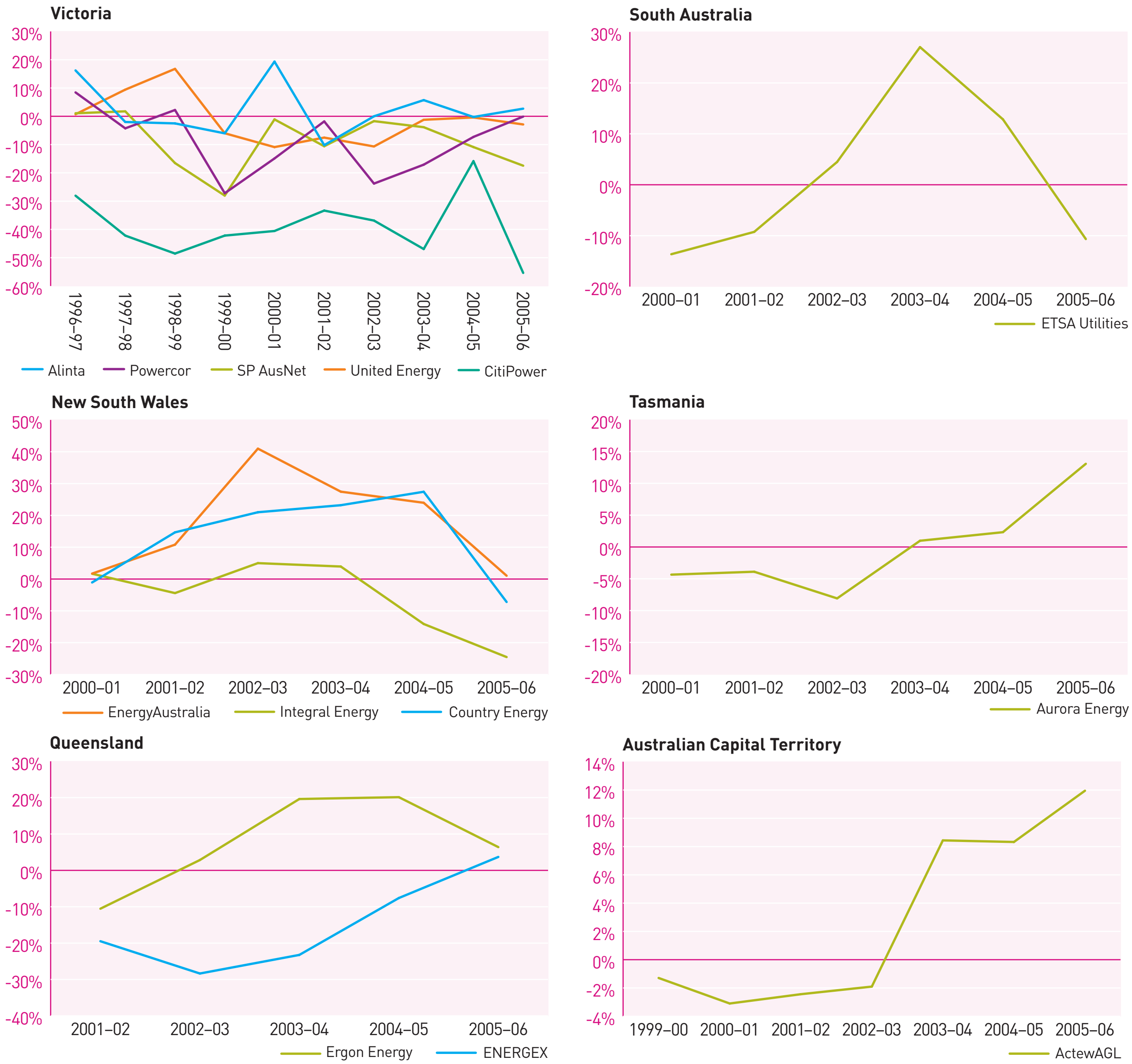
All jurisdictions have their own monitoring and reporting framework on service quality. In addition, the Utility Regulators Forum (URF) developed a national framework in 2002 for distribution businesses to report against common performance criteria.[8] All NEM jurisdictions report against the criteria, which address:

> reliability (the continuity of electricity supply through the network)
> technical quality (for example, voltage stability)
> customer service (for example, on-time provision of services and the adequacy of call centre performance).

8 Utility Regulators Forum, *National regulatory reporting for electricity distribution and retailing businesses*, Discussion paper, March 2002.

Figure 5.7

Operating and maintenance expenditure—variances from target



Source: Regulatory determinations and distribution network performance reports published by ESC (Vic); IPART (NSW); QCA (Qld); ESCOSA (SA); OTTER (Tas); and ICRC (ACT).

Jurisdictions regulate the service performance of distribution networks through schemes that include:

- the monitoring and reporting of reliability, technical quality and customer service outcomes against standards set out in legislation, regulations, licences and codes. There may be sanctions for non-compliance.
- financial incentive schemes for distribution businesses to maintain—and improve—service standards over time. The Victorian, South Australian and Tasmanian regulators administer the schemes as part of the economic regulation of the networks. Victoria and Tasmania currently use service incentive schemes that apply an 's-factor' approach.[9] The South Australian scheme, which does not apply an s-factor, focuses on customers with poor reliability outcomes.
- guaranteed customer service levels (GSLs) that, if not met, require a network business to make payments to affected customers. Typically, the schemes are made available only to small customers. The service level guarantees relate to network reliability, technical quality of service and customer service. Each of the NEM jurisdictions implements a GSL scheme.

There is considerable variation in the detail of these schemes from jurisdiction to jurisdiction. Box 5.1 provides a case study of the Victorian framework.

Reliability

Reliability refers to the continuity of electricity supply to customers, and is a key performance indicator that impacts on customers. The following discussion on distribution reliability should be read in conjunction with essay B of this report, which examines reliability across the broader power supply chain.

A reliable distribution network keeps interruptions or outages in the transport of electricity down to acceptable levels. Various factors, both planned and unplanned, can impede network reliability.

- A planned interruption occurs when a distributor needs to disconnect supply to undertake maintenance or construction works. Such interruptions can be timed for minimal impact.
- Unplanned outages occur when equipment failure causes the supply of electricity to be disconnected unexpectedly. There are often routine external causes, such as damage caused by trees, birds, possums, vehicle impacts or vandalism. Networks can also be vulnerable to extreme weather, such as bushfires or storms. There may be ongoing reliability issues if a network has inadequate maintenance or is utilised near its capacity limits at times of peak demand. Sometimes these factors occur in combination.

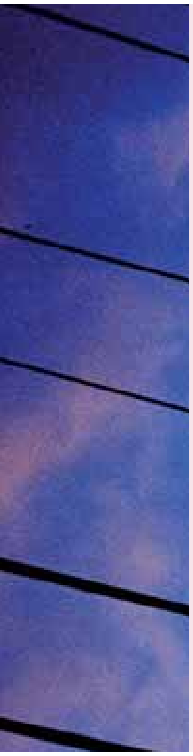
The impact of an outage depends on customer load, the design of the network, maintenance practices and the time taken by a distributor to restore supply after an interruption. Unlike generation and transmission, the impact of a distribution outage tends to be localised to a part of the network.

Jurisdictions track the reliability of distribution networks against performance standards to assess whether they are operating at a satisfactory level. The standards take account of the trade-off between improved reliability and cost. Ultimately, customers must pay the cost of investment, maintenance and other solutions needed to deliver a reliable power system. It would therefore be inefficient to try to eliminate every possible interruption. Rather, an efficient outcome would reflect the level of service that customers are willing to pay for. There has been some research on the willingness of electricity customers to pay higher prices for a reliable electricity supply. A 1999 Victorian study found that more than 50 per cent of customers were willing to pay a higher price to improve or maintain their level of supply reliability.[10] However, a 2003 South Australian survey indicated that customers were willing to pay for improvements in service only to poorly serviced customer areas.[11]

9 The use of s-factor schemes is discussed in the context of electricity transmission in section 4.6 of this report.

10 KBA, *Understanding customers' willingness to pay: Components of customer value in electricity supply*, 1999.

11 The survey found that 85 per cent of consumers were satisfied with their existing level of service and were generally unwilling to pay for improvements in these levels. It found that there was a willingness to pay for improvements in service only to poorly served consumers. On this basis, ESCOSA has focused on providing incentives to improve the reliability performance for the 15 per cent of worst served consumers, while maintaining average reliability levels for all other customers. See ESCOSA, *2005–2010 Electricity distribution price determination, part A*, April 2005; and KPMG, *Consumer preferences for electricity service standards*, March 2003.



Box 5.1 Case Study—service standard regimes in Victoria

The Victorian regulatory regime, administered through the ESC, implements a suite of service standard regimes for electricity distribution businesses. The regimes include a service-standards reporting framework, a service-standards incentive mechanism and a GSL payment scheme. All are benchmarked annually against predetermined targets.

For monitoring and reporting purposes, the ESC tracks:

- reliability outcomes, based on the URF indicators
- reliability experienced by the worst supplied 15 per cent of customers
- technical quality of supply measures, such as voltage stability
- customer service measures, such as call centre performance.

There is some overlap between these measures and those used in the financial incentive scheme that is part of the regulation of network price caps. For the 2006–10 regulatory period, the ESC is tracking network performance against specific reliability standards and call centre performance. The ESC converts outcomes to a standardised 's-factor' measure that provides the basis for financial bonuses and penalties.

Under the GSL scheme, Victoria requires distributors to pay compensation to customers when they have failed to meet minimum thresholds for acceptable levels of reliability and customer service. The GSLs for reliability relate to low supply reliability and delays in restoring lost supply. The GSLs for customer service relate to failures to meet on-time appointments, customer connections and repair of streetlights.

Further information: Essential Services Commission, *Electricity distribution businesses — comparative performance report 2005*, 2006.

In practice, the trade-offs between improved reliability and cost result in standards for distribution networks being less stringent than for generation and transmission. This reflects the localised effects of distribution outages, compared with the potentially widespread geographical impact of a generation or transmission outage. At the same time, the capital intensive nature of distribution networks makes it very expensive to build in high levels of redundancy (spare capacity) to improve reliability.

For similar reasons, there tend to be different reliability standards for different feeders (parts) of a distribution network. For example, a higher reliability standard is usually required of a central business district (CBD) network with a large customer base and a concentrated load density than for a highly dispersed rural network with a small customer base and low load density. While the costs of redundancy in a dispersed rural network are relatively high, few customers are likely to be affected by an outage.

Reliability data—Utility Regulators Forum indicators

All jurisdictions have their own monitoring and reporting framework on reliability. In addition, the URF has adopted four indicators of distribution network reliability which are widely used in Australia and overseas. The indicators relate to the average frequency and duration of network interruptions or outages (table 5.4). The indicators do not distinguish between the nature and size of loads that are affected by supply interruptions.

In most jurisdictions, distribution businesses are required to report performance against the SAIDI, SAIFI and CAIDI indicators (table 5.4). Jurisdictional regulators audit, analyse and publish the results[12], typically down to feeder level (CBD, urban and rural) for each network.

12 The distribution businesses publish this data in the first instance in New South Wales. IPART publishes periodic summaries of the data.

Table 5.4 **Reliability measures—distribution**

INDEX	MEASURE	DESCRIPTION
SAIDI	system average interruption duration index	average total number of minutes that a distribution network customer is without electricity in a year (excludes interruptions of one minute or less)
SAIFI	system average interruption frequency index	average number of times a customer's supply is interrupted per year
CAIDI	customer average interruption duration index	average duration of each interruption (minutes)
MAIFI	momentary average interruption frequency index	average number of momentary interruptions (of one minute or less) per customer per year

Source: URF, *National regulatory reporting for electricity distribution and retailing businesses*, 2002.

Tables 5.5 and 5.6 and figure 5.8 set out summary data for the SAIDI and SAIFI indicators for NEM jurisdictions, including NEM-wide averages. PB Associates developed the data for the AER from the reports of jurisdictional regulators and from reports prepared by distribution businesses for the regulators.

There are a number of issues with the reliability data that limit the validity of any performance comparisons. In particular, the data relies on the accuracy of the network businesses' information systems, which may vary considerably. There are also geographical, environmental and other differences between the states and between networks within particular states.

In addition, there are differences in the approach of each jurisdiction to excluded events. The URF agreed that in some circumstances, reliability data should be normalised to exclude interruptions that are beyond the control of a network business.[13] In practice, there are differences between jurisdictions in the approval and reporting of exclusions. More generally, there is no consistent approach to auditing performance outcomes. Finally, these are relatively new data series in some jurisdictions, and the quality of reporting is likely to improve over time.

Noting these caveats, the SAIDI data indicates that since 2000–01 the average duration of outages per customer tended to be lower in Victoria and South Australia than other jurisdictions—despite some community concerns that privatisation might adversely affect service quality. New South Wales recorded a significant decline in outage time in the three years to 2005–06, and was the only jurisdiction to improve its performance in that year. Average reliability in Queensland tended to be lower than in other jurisdictions. It should be noted that Queensland is subject to significant variations in performance, in part because of its large and widely dispersed rural networks, and extreme weather events. These characteristics make it more vulnerable to outages than some other jurisdictions.

The NEM-wide SAIDI averages rely on the jurisdictional data, and are therefore subject to the caveats outlined above. In addition, the NEM averages include a number of assumptions to allow comparability over time (see notes to tables 5.5 and 5.6). Noting these cautions, the data indicates that distribution networks in the NEM have delivered reasonably stable reliability outcomes over the last few years. NEM-wide SAIDI remained in a range of about 200–270 minutes between 2000–01 and 2005–06. This estimate excludes the impact of a cyclone that affected large parts of Queensland in 2006.

There appears to have been an overall improvement in the average frequency of outages (SAIFI) across the NEM since 2000. On average distribution customers in the NEM experience outages around twice a year, but two to three times a year in Queensland.

13 The URF definitions exclude outages that (i) exceed a threshold SAIDI impact of three minutes, (ii) are caused by exceptional natural or third party events and (iii) the distribution business cannot reasonably be expected to mitigate the effect of by prudent asset management.

Table 5.5 System average interruption duration index—SAIDI (minutes)

	OUTAGE DURATION						
JURISDICTION	1999–00	2000–01	2001–02	2002–03	2003–04	2004–05	2005–06
Vic	156	183	152	151	161	132	165
NSW & the ACT		175	324	193	279	218	191
Qld		331	275	332	434	283	315
SA		164	147	184	164	169	199
NEM weighted average	156	211	246	211	268	202	211

Table 5.6 System average interruption frequency index—SAIFI

	OUTAGE FREQUENCY INDEX						
JURISDICTION	1999–00	2000–01	2001–02	2002–03	2003–04	2004–05	2005–06
Vic	2.1	2.1	2.0	2.0	2.2	1.9	1.8
NSW & the ACT	1.7	2.5	2.6	1.4	1.6	1.6	1.8
Qld		3.0	2.8	3.3	3.4	2.7	2.7
SA		1.7	1.6	1.8	1.7	1.7	1.9
NEM weighted average	1.6	2.4	2.4	2.1	2.2	1.9	2.0

Notes: PB Associates developed the data estimates for the AER from the reports of jurisdictional regulators and from reports prepared by distribution businesses for the regulators. Queensland data for 2005–06 is normalised to exclude the impact of a severe cyclone. Victorian data is for the calendar year ending in that period (for example, Victorian 2005–06 data is for calendar year 2005). NEM averages exclude New South Wales and Queensland (2000–01) and Tasmania (all years).

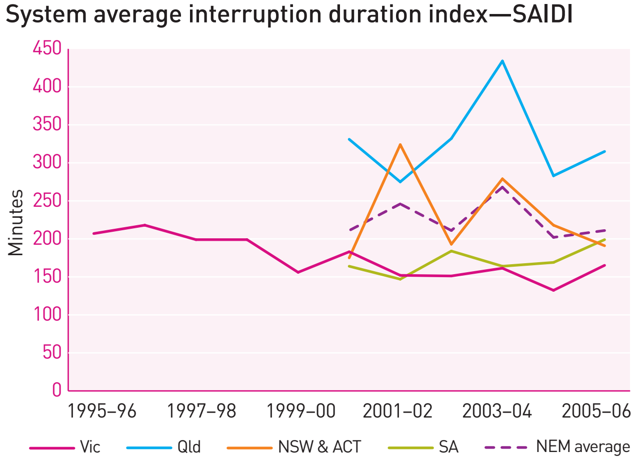
Source: PB Associates (unpublished) and performance reports published by ESC (Victoria); IPART (New South Wales); QCA (Queensland); ESOCSA (South Australia); OTTER (Tasmania); ICRC (the Australian Capital Territory); EnergyAustralia; Integral Energy and Country Energy.

Table 5.7 Feeder categories

FEEDER CATEGORY	DESCRIPTION
central business district	predominately supplies commercial, high-rise buildings, through an underground distribution network containing significant interconnection and redundancy when compared to urban areas
urban	a feeder, which is not a CBD feeder, with actual maximum demand over the reporting period per total feeder route length greater than 0.3 MVA/km
rural short	a feeder which is not a CBD or urban feeder with a total feeder route length less than 200 km
rural long	a feeder which is not a CBD or urban feeder with a total feeder route length greater than 200 km

Source: Utilities Regulators Forum, *National regulatory reporting for electricity distribution and retailing businesses*, 2002.

Figure 5.8
System average interruption duration index—SAIDI



Source: PB Associates (unpublished). See notes to tables 5.5 and 5.6.

Reliability of distribution networks by feeder

Given the diversity of network characteristics, it may be more meaningful to compare network reliability on a feeder category basis than on a statewide basis. Feeders are used to carry electricity from bulk distribution hubs to the low-voltage networks that move electricity to customers. The URF defines four categories of feeder based on geographical location (table 5.7).

Figures 5.9a–5.9d set out the average duration of supply interruptions per customer (SAIDI) for the networks from 2002–03 to 2005–06, for each feeder type, subject to data availability. The charts set out normalised data that excludes outages deemed to be beyond the control of the networks—for example, outages caused by cyclones or bushfires. As a general principle, it would be unreasonable to assess performance unless the impact of such events is excluded. For the sake of completeness, the excluded outages are shown separately as dotted lines. Total outages in a period are the sum of the normalised and excluded data.

As noted, it is difficult to make reliable comparisons between jurisdictions—even based on the normalised data—because of differences in approach to exclusions and auditing practices. Any attempt to compare performance should also take account of geographical, environmental and other differences between the networks. In addition, care should also be taken in drawing conclusions from a short time series of data. That said, it is apparent that CBD and urban customers tend to experience better reliability than rural customers. This reflects that reliability standards have regard to the differing cost-benefit reliability equations of each part of a network. To illustrate, there are likely to be more severe economic consequences from a network outage on a CBD feeder compared to a similar outage on a remote rural feeder where customer bases and loads are more dispersed. CBD networks are therefore designed for high reliability, and include the use of underground feeders, which are less vulnerable to outages.

In summary, in the period from 2002–03 to 2005–06:

- CBD feeders were more reliable than other feeders. Most CBD customers experienced outages totalling less than 30 minutes per year.
- Urban customers typically experienced normalised outages totalling around 30 to 150 minutes per year, but higher for Ergon Energy (Queensland) customers. Queensland, New South Wales and the Australian Capital Territory customers also faced significant interruptions that were excluded from the normalised data. There were significant improvements over the four-year period for the Victorian networks and ENERGEX (Queensland).
- Rural short customers typically experienced normalised outages of around 100 to 300 minutes per year. Some New South Wales and Queensland customers faced a higher duration of outages, with Ergon Energy recording up to 600 minutes. There were significant exclusions for some networks.
- With a feeder route length of more than 200 km, rural long customers experience the least reliable electricity supply. Rural long feeders are prevalent in discussions of worst serving feeders. Rural long customers in Victoria and South Australia experienced outages of around 200 to 400 minutes per year on average, but were generally around 200 minutes in 2005–06. In some years outages times exceeded 600 minutes for some New South Wales customers, and 1000 minutes for Queensland customers. The Victorian networks, EnergyAustralia (New South Wales) and Aurora Energy (Tasmania) recorded significant improvements over the period. The high level of exclusions for Ergon Energy in 2005–06 relates to extreme weather events.

Figure 5.9a

CBD feeders—Average duration of supply interruptions per customer (SAIDI) 2002–03 to 2005–06

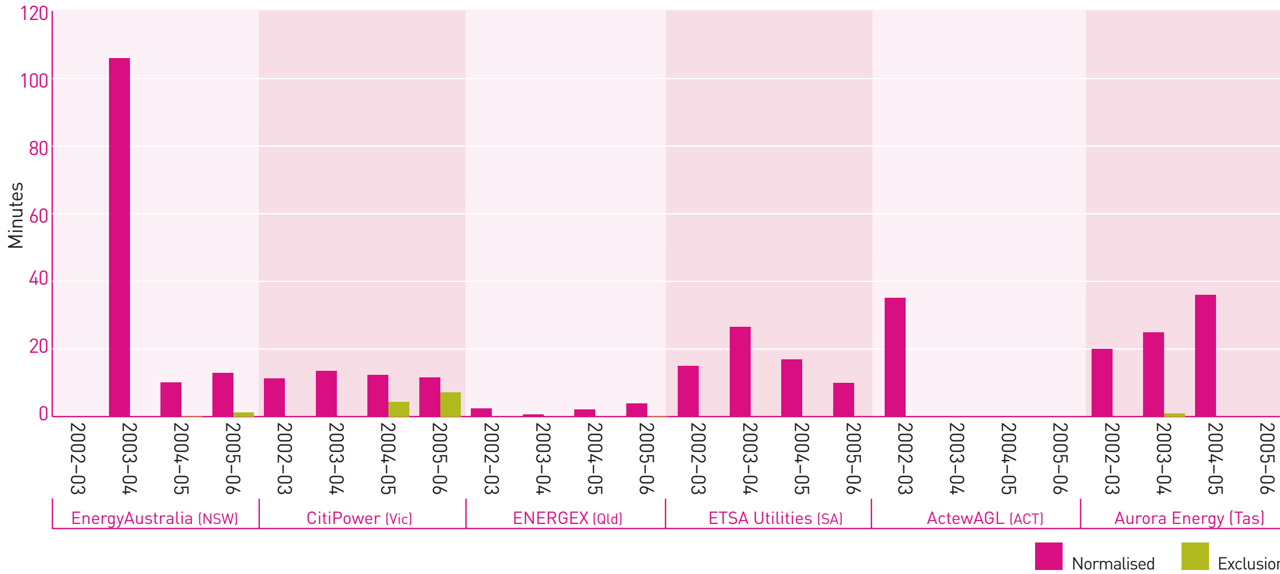
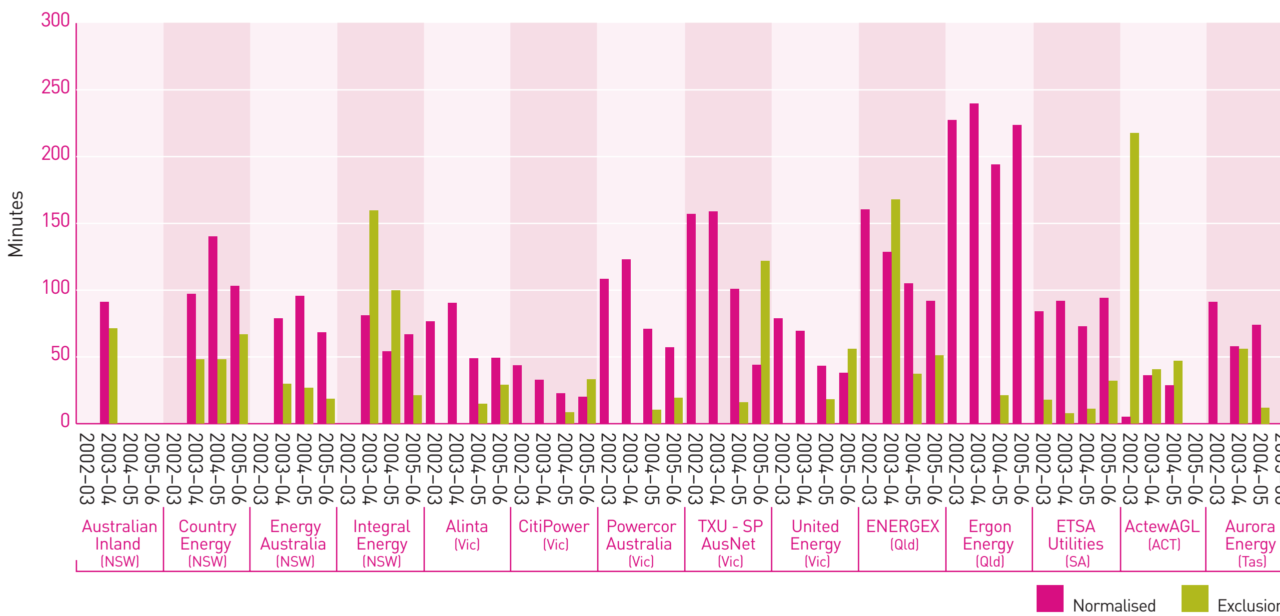


Figure 5.9b

Urban feeders—Average duration of supply interruptions per customer (SAIDI) 2002–03 to 2005–06



Notes: Figures 5.9a–d: Victorian data is for the calendar year ending in that period (for example, Victorian 2005–06 data is for calendar year 2005). Exclusions for ActewAGL in 2002–03 are not shown. Exclusions for Ergon Energy (urban and rural short) in 2005–06 are not shown.

Figure 5.9c

Rural short feeders—Average duration of supply interruptions per customer (SAIDI) 2002–03 to 2005–06

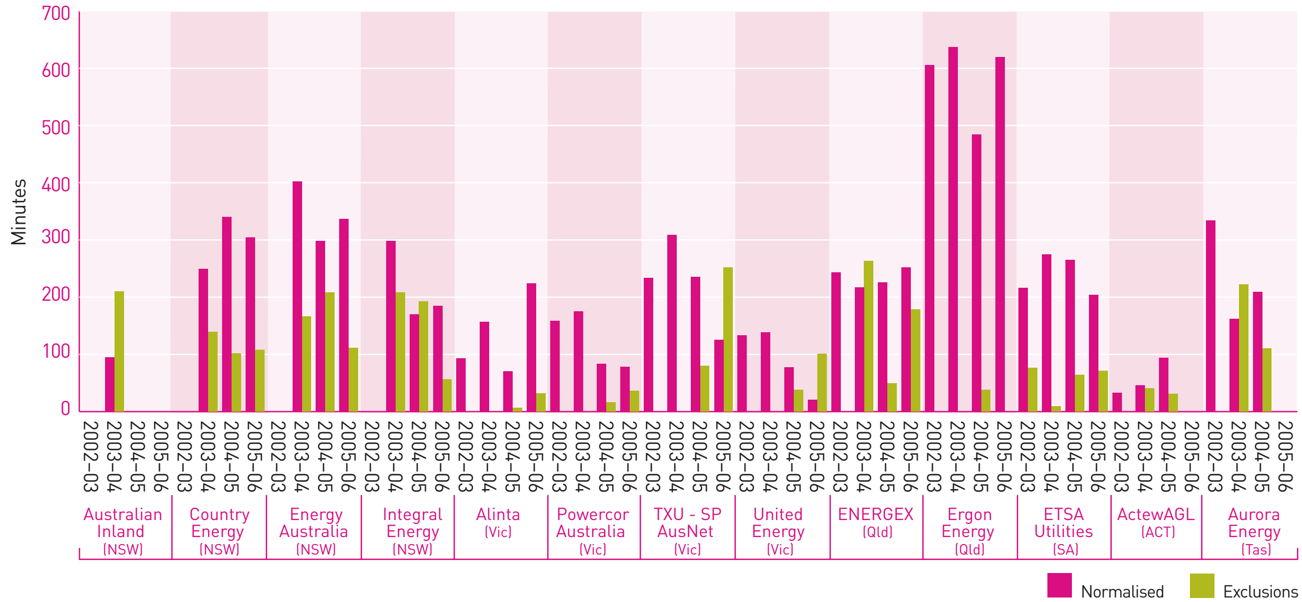
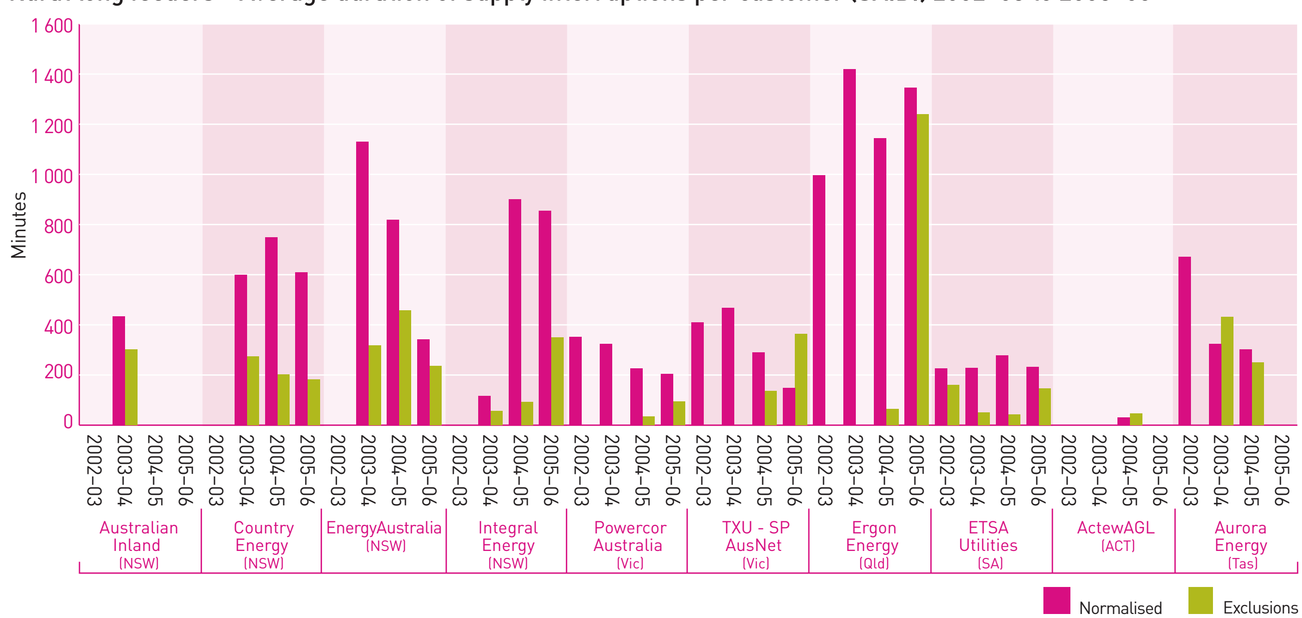


Figure 5.9d

Rural long feeders—Average duration of supply interruptions per customer (SAIDI) 2002–03 to 2005–06



Sources for figures 5.9a–d: Distribution network performance reports published by ESC (Vic); IPART (NSW); QCA (Qld); ESCOSA (SA); OTTER (Tas); ICRC (ACT); EnergyAustralia; Integral Energy; and Country Energy.

Box 5.2 Case Study—Performance of the Victorian and South Australia networks against service targets

Victoria

In the 2001–05 regulatory period, Victoria's ESC set service targets (standards) for three performance measures—average minutes-off-supply per customer, the average number of interruptions per customer and the average interruption duration. Different targets were set for each network, taking account of specific characteristics.

Figure 5.10 sets out the percentage variances between target and actual minutes-off-supply (SAIDI) for the five Victorian distribution networks from 2001 to 2005. Over this period the regulator set sliding targets for improved reliability over time. There is a service standards incentive mechanism, with financial incentives for meeting targets, and penalties for underperformance. The chart indicates that most Victorian networks consistently bettered their SAIDI targets. The SP AusNet (previously TXU) network was below target in most years, but improved its performance in 2005.

South Australia

In South Australia, the Essential Services Commission (ESCOSA) sets reliability targets as part of a service incentive scheme. The scheme examines the reliability of components of the distribution network that have experienced poor past performance.[14] In the year to December 2005, ETSA Utilities performed favourably against its incentive scheme targets, resulting in an increase in allowable revenues.

ESCOSA also reports the performance of ETSA Utilities against best endeavours SAIDI and SAIFI standards set out in the Electricity Distribution Code. ETSA Utilities failed to achieve many of these targets in 2005–06 (table 5.8).

Table 5.8 Reliability outcomes against target—ETSA Utilities 2005–06

REGION	SAIFI (FREQUENCY)			CAIDI (MINUTES)			SAIDI (MINUTES)		
	Target	Performance		Target	Performance		Target	Performance	
Adelaide Business Area	0.30	0.20	✓	80	55	✓	25	11	✓
Major Metropolitan Areas	1.40	1.61	✗	82	88	✗	115	142	✗
Central	2.10	1.64	✓	115	146	✗	240	239	✓
Eastern Hills/ Fleurieu Peninsula	3.30	3.72	✗	105	111	✗	350	414	✗
Upper North & Eyre Peninsula	2.50	3.31	✗	150	184	✗	370	610	✗
South East	2.70	2.36	✓	120	108	✓	330	256	✓
Kangaroo Island	na	9.34	na	na	145	na	450	1354	na
Total (state wide)	1.70	1.88		97	107		165	201	

na not applicable.

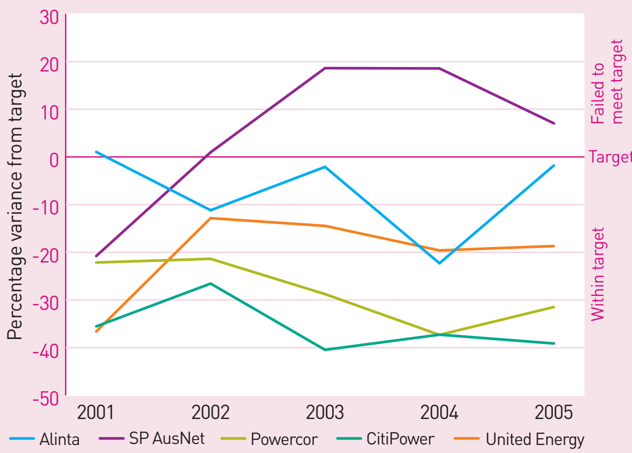
Source: ESCOSA, *2005–06 Distribution network performance report,* November 2006.

14 Reliability targets under the scheme are set for feeders that have experienced two consecutive years of at least three interruptions, or two consecutive years of more than 180 minutes off supply.

Care should be taken in comparing the performance of networks against locally set targets. For example, while ETSA Utilities did not meet some of its best endeavours SAIDI targets in 2005–06, it met its incentive scheme target and has generally recorded outage durations below the national average. More generally, some jurisdictions may set more stringent standards than others.

Figure 5.10

Minutes off supply against service incentive targets—Victorian distribution networks



Source: ESC, *Electricity distribution businesses —comparative performance report 2005*, October 2006.

Performance against reliability standards

Jurisdictions track the reliability of distribution networks against performance standards that are set out in monitoring and reporting frameworks, service standard incentive schemes and guaranteed service level payment schemes. Standards provide a benchmark to assess whether a network is performing to a satisfactory standard. As noted, the standards effectively weigh the costs of improving network reliability through investment, maintenance and other solutions against the benefits. Such assessments take account of the specific characteristics of each network.

To illustrate the use of reliability standards, box 5.2 provides a case study of the performance of the Victorian and South Australian networks against standards developed for incentive schemes that form part of the regulatory framework. Tasmania (not covered in this case study) has recently commenced a similar scheme.

Technical quality of supply

The technical quality of electricity supply through a distribution network can be affected by issues such as voltage dips, swells and spikes, and television or radio interference. Some problems are network-related (for example, the result of a network limit or fault) but in other cases may trace to an environmental problem or the customer.

Network businesses report on technical quality of supply by disaggregating complaints into categories and their underlying causes. There are a number of issues in making performance comparisons between jurisdictions—in particular, the definition of 'complaint' adopted by each business may vary widely.

The complaint rate for technical quality of supply issues in 2004–05 and 2005–06 was less than 0.1 per cent of customers for most distribution networks in the NEM.

Customer service

Network businesses report on their responsiveness to a range of customer service issues, including:

- timely connection of services
- timely repair of faulty street lights
- call centre performance
- customer complaints.

Tables 5.9 and 5.10 provide a selection of customer service data, where available, from state and territory regulators.[15] As noted, it is difficult to make reliable performance comparisons between jurisdictions due to the significant differences between networks, as well as differences in definitions and information, measurement and auditing systems. Noting these contexts, the following observations should be interpreted with caution:

- The New South Wales and Victorian networks completed over 99.5 per cent of supply connections on time in 2003–04, 2004–05 and 2005–06. South Australia achieved a slightly lower rate. The Queensland networks recorded a significant improvement in this area in 2005–06 (table 5.9).
- Country Energy and EnergyAustralia (New South Wales) took longer to repair faulty streetlights than other networks in 2004–05 and 2005–06, but their rates of completing repairs by the agreed date was generally comparable with other networks. Ergon Energy (Queensland) and CitiPower (Victoria) achieved lower rates of on-time repair work than the other networks in 2005–06 (table 5.9).
- Tasmanian customers were more likely to have a complaint call answered than mainland customers, while call abandonment levels for ENERGEX (Queensland) and Integral Energy (New South Wales) customers significantly reduced between 2003–04 and 2005–06. Customers of Country Energy (New South Wales) and United Energy (Victoria) faced a higher risk than customers elsewhere of having their call unanswered in 2005–06 (table 5.10).
- The Queensland and South Australian networks generally provided the quickest response to customer phone calls. Most networks improved their call centre response time between 2003–04 and 2005–06, with EnergyAustralia and Integral Energy (New South Wales), CitiPower and Powercor (Victoria) and ENERGEX and Ergon Energy (Queensland) all registering sharp improvements in this area (table 5.10).

15 More comprehensive data is available on the websites of the jurisdictional regulators.

Table 5.9 Timely provision of service indicators

NETWORK	JURISDICTION	PERCENTAGE OF SUPPLY CONNECTIONS NOT PROVIDED BEFORE THE AGREED DATE			PERCENTAGE OF STREETLIGHT REPAIRS NOT COMPLETED BY AGREED DATE		AVERAGE NUMBER OF DAYS TO REPAIR FAULTY STREETLIGHT	
		2003–04	2004–05	2005–06	2004–05	2005–06	2004–05	2005–06
Country Energy	NSW	0.03	0.02	0.02[1]	1.3	1.0	9.0	8.0
EnergyAustralia	NSW	0.01	0.01	0.02[1]	6.6	6.0	8.0	9.0
Integral Energy	NSW	0.01	0.01	0.02[1]	5.5	0.9	2.0	2.0
Alinta (AGL)	Vic	0.04	0.14	0.12	6.1	6.9	2.0	3.0
CitiPower	Vic	0.00	0.00	0.02	7.8	11.3	2.3	3.0
Powercor	Vic	0.04	0.13	0.12	0.3	0.9	2.0	2.0
SP AusNet	Vic	0.21	0.03	0.21	0.0	0.2	2.0	2.0
United Energy	Vic	0.22	0.12	0.05	0.8	2.8	1.4	1.0
ENERGEX	Qld	4.40[2]	3.98[2]	0.62[2]	5.4	4.8	3.5	4.5
Ergon Energy	Qld	4.90[2]	6.62[2]	0.84[2]	9.7	21.5	2.8	3.9
ETSA	SA	1.23	0.91	1.33	4.5	5.5	3.8	3.6
Aurora Energy	Tas	–	–	–	10.5	–	–	–
ACT Utilities	ACT	–	–	–	–	–	–	–

Table 5.10 Call centre performance

NETWORK	JURISDICTION	PERCENTAGE OF ABANDONED CALLS BEFORE REACHING A HUMAN OPERATOR			PERCENTAGE OF CALLS ANSWERED BY A HUMAN OPERATOR WITHIN 30 SECONDS		
		2003–04	2004–05	2005–06	2003–04	2004–05	2005–06
Country Energy	NSW	24.5	41.2	42.6	66.7	48.4	47.2
EnergyAustralia	NSW	12.3	10.5	10.5	46.4	44.6	81.3
Integral Energy	NSW	16.0	6.0	3.2	58.0	81.0	89.0
Alinta (AGL)	Vic	–	0.9	5.0	70.8	73.8	75.2
CitiPower	Vic	–	10.8	10.0	46.4	88.2	89.2
Powercor	Vic	–	5.9	7.0	40.5	90.9	88.7
SP AusNet	Vic	–	8.8	6.0	81.1	79.8	82.7
United Energy	Vic	–	7.7	24.0	61.0	75.6	73.8
ENERGEX	Qld	9.6	4.1	3.9	64.0	80.6	89.4
Ergon Energy	Qld	5.2	2.7	3.5	69.4	77.3	85.1
ETSA Utilities	SA	5.0	4.4	4.0	85.8	86.9	85.2
Aurora Energy	Tas	1.0	1.0	–	–	–	–
ActewAGL	ACT	12.7	16.9	–	76.1	65.6	–

Notes: Tables 5.9 and 5.10: Victorian data is for the calendar year ending in that period (for example, Victorian 2005–06 data is for calendar year 2005).

1. Average performance of all New South Wales distribution networks.
2. Includes new connections only.

Source: Distribution network performance reports published by ESC (Vic); IPART (NSW); QCA (Qld); ESCOSA (SA); OTTER (Tas); ICRC (ACT); EnergyAustralia; Integral Energy; and Country Energy.