EnergyAustralia's City West Cable Tunnel, Sydney (EnergyAustralia)

2 ELECTRICITY NETWORKS

Electricity networks transport power from generators to customers. Transmission networks transport power over long distances, linking generators with load centres. Distribution networks transport electricity from points along the transmission network, and criss-cross urban and regional areas to provide electricity to customers.

2.1 Electricity networks in the NEM

In Australia, each state and territory has electricity transmission networks, with cross-border interconnectors that link some networks (table 2.1). The National Electricity Market (NEM) in eastern and southern Australia provides a fully interconnected network from Queensland through to New South Wales, the Australian Capital Territory (ACT), Victoria, South Australia and Tasmania. The NEM transmission network has a long, thin, low density structure reflecting the location of, and distance between, major demand centres.

The NEM has 13 major electricity distribution networks (table 2.2). Queensland, New South Wales and Victoria have multiple networks, of which each is a monopoly provider in a designated area. Each of the other jurisdictions has one major network. Some jurisdictions also have small regional networks with separate ownership. The total length of distribution infrastructure in the NEM is around 750 000 kilometres—17 times longer than transmission infrastructure.

Figure 2.1 illustrates the transmission and distribution networks in the NEM.

2.1.1 Ownership

Tables 2.1 and 2.2 list ownership arrangements for electricity networks in the NEM. The transmission networks in Victoria and South Australia, and the three direct current network interconnectors (Directlink, Murraylink and Basslink) are privately owned.

Victoria's five distribution networks are also privately owned, while the South Australian network (ETSA Utilities) is leased to private interests. The ACT network has joint government and private ownership. All networks (transmission and distribution) in Queensland, New South Wales and Tasmania are owned by governments.

Aside from governments, there were two principal network owners at June 2010:

- *Cheung Kong Infrastructure* and Hongkong Electric Holdings have a 51 per cent stake in two Victorian distribution networks (Powercor and CitiPower) and a 200 year lease of the South Australian distribution network (ETSA Utilities). The remaining 49 per cent in each network is held by Spark Infrastructure, a publicly listed infrastructure fund in which Cheung Kong Infrastructure has a direct interest.
- *Singapore Power International* owns the Jemena distribution network and has part ownership of the United Energy distribution network, both in Victoria. It has a 50 per cent share in the ACT distribution network (ActewAGL) and a 51 per cent stake in SP AusNet, which owns the Victorian transmission network and SP AusNet distribution network.

These businesses also own a number of gas networks in Australia (see chapter 3).

Victoria has a unique transmission network structure, which separates asset ownership from planning and investment decision making. SP AusNet owns the state's transmission assets, but the Australian Energy Market Operator (AEMO, formerly VENCorp) plans and directs network augmentation. AEMO also buys bulk network services from SP AusNet for sale to customers.

In some jurisdictions, there are ownership links between electricity networks and other segments of the electricity sector. In New South Wales,[1] Tasmania and the ACT,[2] common ownership occurs in electricity distribution and retailing, with ring fencing arrangements for operational separation. Queensland privatised much of its energy retail sector in 2006–07, but Ergon Energy continues to provide both distribution and retail services.

1 In New South Wales, privatisation plans for the contestable sectors of the energy market (generation and retail) will result in structural separation of the distribution and retail sectors (box 1.1, chapter 1).

2 In the ACT, ACTEW Corporation has a 50 per cent share in ActewAGL Retail and ActewAGL Distribution. AGL Energy and Singapore Power International respectively own the remaining shares.

Figure 2.1
Electricity networks in the National Electricity Market

QNI, Queensland – New South Wales Interconnector.

Table 2.1 Electricity transmission networks

NETWORK	LOCATION	LINE LENGTH (KM)	ELECTRICITY TRANSMITTED (GWh), 2008–09	MAXIMUM DEMAND (MW), 2008–09	ASSET BASE (2009 $ MILLION)[1]	INVESTMENT — CURRENT PERIOD (2009 $ MILLION)[2]	CURRENT REGULATORY PERIOD	OWNER
NEM REGION NETWORKS								
Powerlink	Qld	13 106	49 104	8 677	3 979	2 564	1 July 2007 – 30 June 2012	Queensland Government
TransGrid	NSW	12 445	75 744	14 274	4 213	2 440	1 July 2009 – 30 June 2014	New South Wales Government
SP AusNet	Vic	6 553	51 777	10 446	2 265	1 004[3]	1 Apr 2008 – 30 Mar 2014	Publicly listed company (Singapore Power International 51%)
ElectraNet	SA	5 589	13 327	3 408	1 303	659	1 July 2008 – 30 June 2013	Powerlink (Queensland Government), YTL Power Investment, Hastings Utilities Trust
Transend	Tas	3 650	11 031	2 236	950	615	1 July 2009 – 30 June 2014	Tasmanian Government
NEM TOTALS		**41 343**	**200 983**		**12 710**	**7 282**		
INTERCONNECTORS[4]								
Directlink (Terranora)	Qld–NSW	63		180	132		1 July 2005 – 30 June 2015	Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)
Murraylink	Vic–SA	180		220	121		1 Oct 2003 – 30 June 2013	Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)
Basslink	Vic–Tas	375			858[5]		Unregulated	CitySpring Infrastructure Trust (Temesek Holdings (Singapore) 28%)

GWh, gigawatt hours; MW, megawatts.

1. The regulated asset bases are as set at the beginning of the current regulatory period for each network, converted to June 2009 dollars.
2. Investment data are forecast capital expenditure over the current regulatory period, converted to June 2009 dollars.
3. SP AusNet's investment data include forecast augmentation investment by the Australian Energy Market Operator (formerly VENCorp).
4. Not all interconnectors are listed. The unlisted interconnectors, which form part of the state based networks, are Heywood (Victoria – South Australia), QNI (Queensland – New South Wales) and Snowy-Victoria.
5. Basslink is not regulated, so has no regulated asset base. The listed asset value is the estimated construction cost.

Sources: AER, *Transmission network service providers: electricity performance report for 2008–09*, 2010 and previous years; AER/ACCC revenue cap decisions.

Table 2.2 Electricity distribution networks

NETWORK	CUSTOMER NUMBERS	LINE LENGTH (KM)	MAXIMUM DEMAND (MW) (2008–09)	ASSET BASE (2009 $ MILLION)[1]	INVESTMENT — CURRENT PERIOD (2009 $ MILLION)[2]	CURRENT REGULATORY PERIOD	OWNER
QUEENSLAND							
ENERGEX	1 256 574	52 361	4 593	7 867	5 602	1 Jul 2010–30 Jun 2015	Queensland Government
Ergon Energy	636 480	145 904	2 498	7 149	4 866	1 Jul 2010–30 Jun 2015	Queensland Government
NEW SOUTH WALES AND ACT							
EnergyAustralia[3]	1 591 372	49 546	5 918	8 431	7 837	1 Jul 2009–30 Jun 2014	New South Wales Government
Integral Energy	859 718	33 579	3 798	3 744	2 721	1 Jul 2009–30 Jun 2014	New South Wales Government
Country Energy	786 241	189 823	2 332	4 382	3 826	1 Jul 2009–30 Jun 2014	New South Wales Government
ActewAGL	161 061	4 795	…	607	275	1 Jul 2009–30 Jun 2014	ACTEW Corporation (ACT Government) 50%, Jemena (Singapore Power International (Australia)) 50%
VICTORIA							
Powercor	698 509	83 468	2 380	2 132	1 276	1 Jan 2011–31 Dec 2015	Cheung Kong Infrastructure/ Hongkong Electric Holdings 51%, Spark Infrastructure 49%
SP AusNet	609 855	47 999	1 682	2 043	1 365	1 Jan 2011–31 Dec 2015	SP AusNet (listed company, Singapore Power International 51%)
United Energy	620 300	12 707	2 070	1 330	725	1 Jan 2011–31 Dec 2015	Jemena (Singapore Power International (Australia)) 34%, DUET Group 66%
CitiPower	304 957	6 478	1 463	1 240	740	1 Jan 2011–31 Dec 2015	Cheung Kong Infrastructure/ Hongkong Electric Holdings 51%, Spark Infrastructure 49%
Jemena	303 245	5 928	1 011	729	418	1 Jan 2011–31 Dec 2015	Jemena (Singapore Power International (Australia))
SOUTH AUSTRALIA							
ETSA Utilities	807 500	86 634	3 086	2 772	1 549	1 Jan 2011–31 Dec 2015	Cheung Kong Infrastructure/ Hongkong Electric Holdings 51%, Spark Infrastructure 49%
TASMANIA							
Aurora Energy	269 554	25 050	1 073	1 072	631	1 Jan 2008–20 Jun 2013	Tasmanian Government
NEM TOTALS	**8 905 366**	**744 272**		**43 498**	**31 832**		

MW, megawatts.

1. Asset valuation is the opening regulated asset base for the current regulatory period, converted to June 2009 dollars. Regulated asset base data do not include capital contributions except for Queensland. Capital contributions can form a significant proportion of new network investment—for example, they typically account for around 10–20 per cent of distribution network investment in Victoria and over 20 per cent of investment in South Australia.
2. Investment data are forecast capital expenditure over the current regulatory period, converted to June 2009 dollars.
3. EnergyAustralia's distribution network includes 885 kilometres of transmission assets. From 1 July 2009, these assets are treated as distribution assets for the purpose of economic regulation. Future performance of the network will be assessed under the framework applicable to distribution network service providers.

Sources: Regulatory determinations by the AER and OTTER (Tasmania); performance reports by the AER (Victoria), the QCA (Queensland), ESCOSA (South Australia), OTTER (Tasmania), the ICRC (ACT), EnergyAustralia, Integral Energy and Country Energy.

2.1.2 Scale of the networks

Tables 2.1 and 2.2 show the asset values of NEM electricity networks, as measured by the regulated asset base (RAB). In general, the RAB reflects the replacement cost of an asset at the time it was first regulated, plus subsequent new investment, less depreciation. More generally, it indicates relative scale.

Networks in Queensland and New South Wales have significantly higher RABs than those of other jurisdictions. Many factors can affect the size of the RAB, including the basis of original valuation, network investment, the age of a network, geographic scale, the distances required to transport electricity, population dispersion and forecast demand profiles.

The combined opening RABs of distribution networks in the NEM are around $43.5 billion—more than three times the valuation for transmission infrastructure (around $12.7 billion).

2.2 Economic regulation of electricity networks

Energy networks are capital intensive and incur declining marginal costs as output increases, leading to a natural monopoly industry structure. In Australia, the networks are regulated to manage the risk of monopoly pricing. The Australian Energy Regulator (AER) regulates all electricity networks in the NEM. The Economic Regulation Authority regulates networks in Western Australia, and the Utilities Commission regulates networks in the Northern Territory.

2.2.1 Regulatory process and approach

Regulated electricity network businesses must periodically apply to the AER to assess their revenue requirements (typically, every five years). The regulatory process is set out in the National Electricity Law and the National Electricity Rules, as summarised in the following discussion. The AER *State of the energy market 2009* report (sections 5.3 and 6.3) provides more detail.

For a transmission network, the AER must determine a revenue cap that sets the maximum revenue the network can earn during a regulatory period. The range of available control mechanisms is wider in distribution, but generally involves setting a ceiling on the revenues or prices that a network can earn or charge during a period. Control mechanisms in use include:

- *weighted average price caps,* which allow flexibility in individual tariffs within an overall ceiling—used for the New South Wales, Victorian and South Australian networks
- *average revenue caps,* which set a ceiling on revenue yields that may be recovered during a regulatory period—used for the Queensland and ACT networks.

Regardless of the regulatory approach, the AER must forecast the revenue requirement of a business to cover its efficient costs and provide a commercial return. It uses a building block model that accounts for a network's efficient operating and maintenance expenditure, capital expenditure, asset depreciation costs and taxation liabilities, and a commercial return on capital. The Australian Energy Market Commission (AEMC) is reviewing a total factor productivity approach as an alternative to the building block model (box 2.1).

The largest component of network revenue is the return on capital, which accounts for up to two thirds of network revenues. The return on capital is influenced by the size of a network's regulated asset base (and projected investment) and its weighted average cost of capital (the rate of return necessary to cover efficient equity raising and debt costs). An allowance for operating expenditure typically accounts for a further 30 per cent of revenue requirements.

2.2.2 Regulatory timelines and recent AER determinations

Figure 2.2 shows the regulatory timelines for electricity networks in each jurisdiction. In 2010 the AER completed distribution reviews for networks in Queensland and South Australia (released May 2010) and Victoria (released October 2010).

Box 2.1 Total factor productivity approach

In November 2010 the Australian Energy Market Commission (AEMC) published a draft report on using a total factor productivity approach to regulating network revenues and prices.[3] The approach measures how businesses use resources to produce output. It exposes regulated businesses to competitive pressures by linking revenues to industry performance rather than the cost structure of a particular business.

The AEMC identified potential benefits of using this method over the current building block approach:

> a less information intensive approach, with reduced regulatory costs
> reduced information asymmetry between regulated businesses and regulators
> stronger performance incentives for regulated businesses.

It found that applying a total factor productivity approach is likely to have benefits, especially in the distribution sector. It considered, however, that existing regulatory data may not be sufficiently robust or consistent to implement the approach in the short term.

The draft report recommended that the initial focus should be on establishing a better, more consistent data-set to allow for the undertaking of initial trials. The proposed reporting requirements would apply in both the transmission and distribution sectors.

3 AEMC, *Review into the use of total factor productivity for the determination of prices and revenues, draft report*, 2010.

The South Australian and Queensland distribution businesses lodged appeals with the Australian Competition Tribunal over aspects of the AER decisions. The *Market overview* in this report provides information on these appeals.

2.3 Revenues

Figure 2.3 illustrates AER revenue allowances for electricity networks in the current five year regulatory periods compared with previous periods. Combined network revenues were forecast to exceed $55 billion over the current cycle, comprising over $11 billion for transmission and $44 billion for distribution. Average revenues are forecast to rise by around 41 per cent (in real terms) over those of the previous regulatory periods.

Under AER determinations in 2010 for the distribution sector, average revenues are forecast to rise by around 37 per cent in Queensland, 24 per cent in South Australia and 11 per cent in Victoria. The largest increases in current determinations (over 70 per cent) are forecast for the EnergyAustralia and Country Energy networks in New South Wales (figure 2.3). As outlined in section 2.4.1, these outcomes reflect differences in the operating environments and cost drivers of each network.

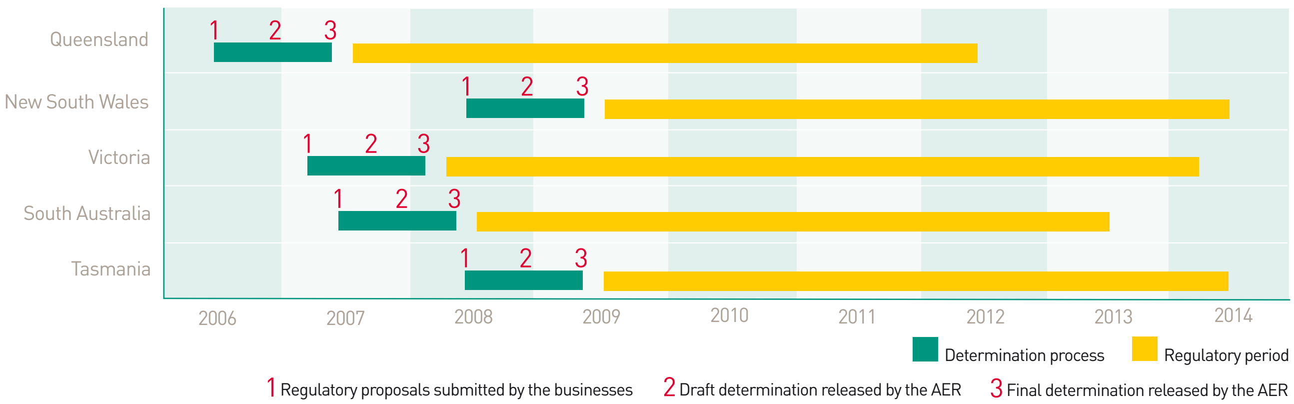
2.4 Electricity network investment

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

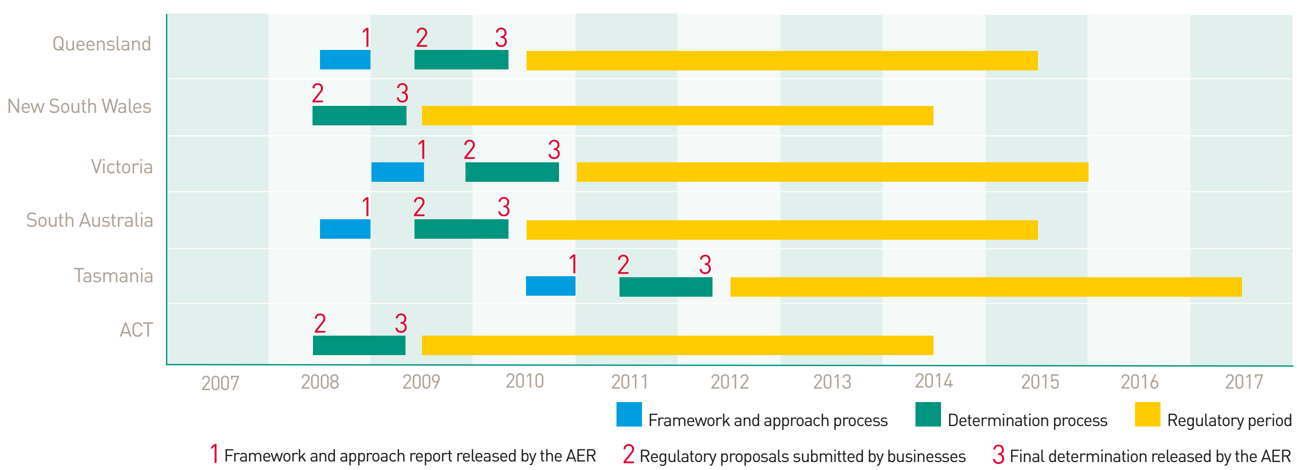
The regulatory process aims to create incentives for efficient investment. At the start of a regulatory period, the AER approves an investment (capital expenditure) forecast for each network. It can also approve contingent projects—large investment projects that are foreseen at the time of the revenue determination, but that involve significant uncertainty.

Figure 2.2
Indicative timelines for AER determinations on electricity networks

Electricity transmission



Electricity distribution



Note: The New South Wales and ACT distribution determinations were developed under transitional Electricity Rules, which did not provide for a framework and approach process.

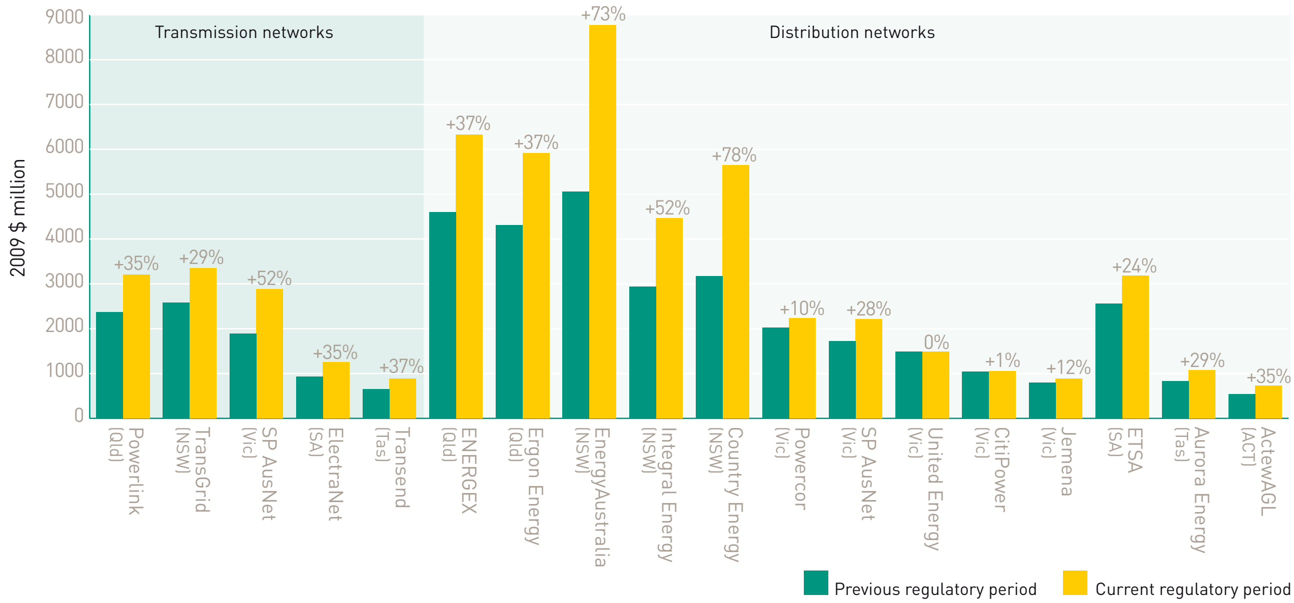
While the regulatory process approves a pool of funds for capital expenditure, individual projects must undergo an economic efficiency assessment that aims to identify the most efficient method—accounting for network augmentation and non-network options—to meet an identified need.

There are separate versions of the test for distribution and transmission. For distribution networks, the regulatory test requires a business to determine that a proposed augmentation passes a cost–benefit analysis or provides a least cost solution to meet network reliability standards.[4]

A new regulatory investment test for transmission (RIT-T) took effect on 1 August 2010.[5] Transmission projects are now assessed through a single consultation and assessment framework that is more comprehensive and applies to a wider range of investment projects than previously. It also gives more prescription of the

4 AER, *Regulatory test for network augmentation, version 3,* 2007.
5 AER, *Regulatory investment test for transmission,* 2010

Figure 2.3
Electricity network revenues



Notes:

Current regulatory period revenues are forecasts in regulatory determinations.

All data are converted to June 2009 dollars.

Sources: Regulatory determinations by the AER and OTTER (Tasmanian distribution).

market benefits and costs that the analysis can consider. In September 2009 the AEMC recommended that a test similar to the RIT-T apply in distribution.[6]

The AER in 2010 reviewed the compliance of TransGrid (New South Wales) with the regulatory test, in regard to a proposed 330 kilovolt (kV) transmission line from Dumaresq to Lismore.[7] It found shortcomings in TransGrid's analysis and process in deciding to build the line. TransGrid subsequently committed to the AER to improve future processes.

2.4.1 Investment trends

Figure 2.4 illustrates investment allowances for electricity networks in the current five year regulatory periods compared with previous regulatory periods. It shows the RAB for each network as a scale reference.

Network investment over the current five year cycle is forecast at over $7 billion for transmission networks and $32 billion for distribution networks. Investment is set to rise by around 84 per cent in transmission and 54 per cent in distribution (in real terms). The key drivers of rising investment include:

> more rigorous licensing conditions and other obligations for network security, safety and reliability
> load growth and rising peak demand
> new connections
> the need to replace ageing assets, given much of the networks were developed between the 1950s and 1970s.

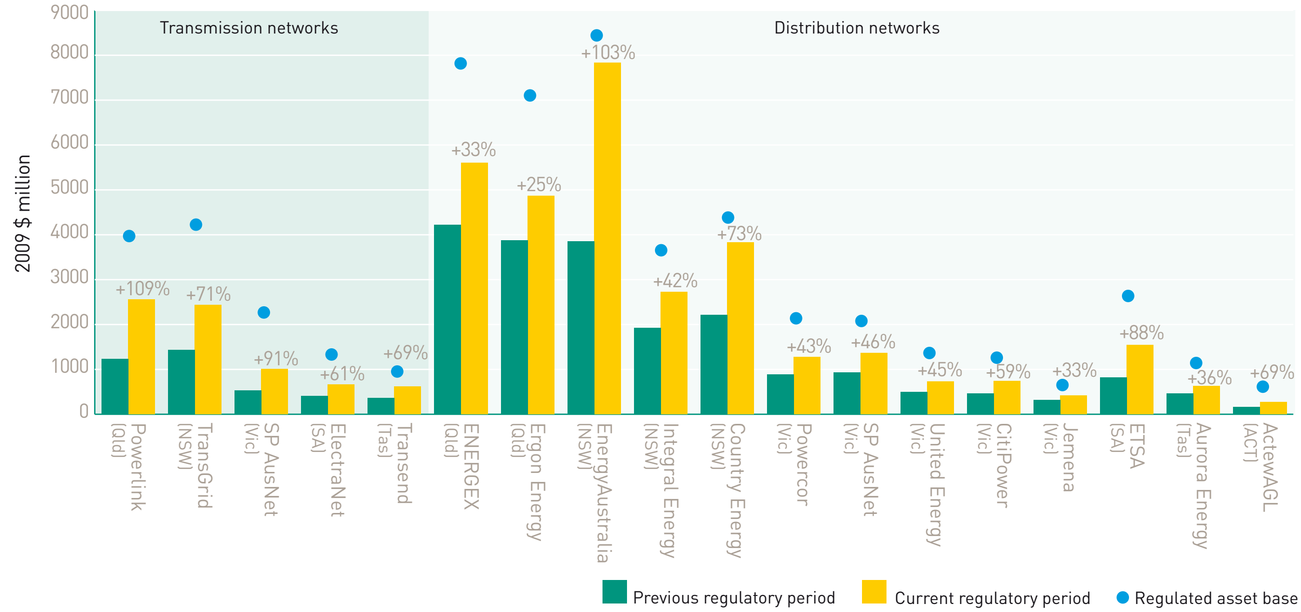
Other drivers include changes to system operation due to climate change policies and the introduction of smart meters and grids.

While these factors are driving higher levels of investment, each network faces a different blend of challenges—for example, each network has unique issues relating to its age and technology, its load characteristics, the costs of meeting the demand for

6 AEMC, *Review of national framework for electricity distribution network planning and expansion, final report*, 2009.

7 AER, *Investigation report, Compliance with the planning and network development provisions of the National Electricity Rules—TransGrid*, 2010.

Figure 2.4
Electricity network investment



Notes:

Regulated asset bases are as at the beginning of the current regulatory periods.

Investment data reflect forecast capital expenditure for the current regulatory period (typically, five years). See tables 2.1 and 2.2 for the timing of current regulatory periods.

EnergyAustralia's distribution network includes 885 kilometres of transmission assets.

SP AusNet includes augmentation investment by AEMO (formerly VENCorp).

All data are converted to June 2009 dollars.

Sources: Regulatory determinations by the AER and OTTER (Tasmanian distribution).

new connections, and its licensing, reliability and safety requirements. Other issues are common to all network businesses—for example, rising input and finance costs.

As required by the regulatory regime, the AER accounts for these factors when assessing the needs of each network. Electricity distribution determinations in 2010 reflected that:

- the Queensland networks have pressing capital requirements associated with population growth, new connections and industrial demand, as well as rising energy use per customer. The networks are also obliged to improve performance in response to stricter reliability standards
- the South Australian network requires significant investment to meet rising load growth and peak demand driven by the use of air conditioners during summer heatwaves. The network also needs to address reliability risks from ageing assets and new reliability standards for the Adelaide central business district (involving complementary upgrades to transmission and distribution systems). Investment costs in both Queensland and South Australia have also been rising as a result of real increases in the cost of labour and materials
- the Victorian distributors operate mostly mature and comparatively reliable networks. While the AER considers past expenditure (in what has been a relatively stable operating environment) provides a good starting point for assessing future needs, it also accounted for the need to replace ageing infrastructure, address Victoria's new bushfire safety standards, and maintain reliability in the face of growing costs and demand. While these considerations led it to approve higher levels of investment, the AER did not accept the full extent of the increases proposed by distribution businesses

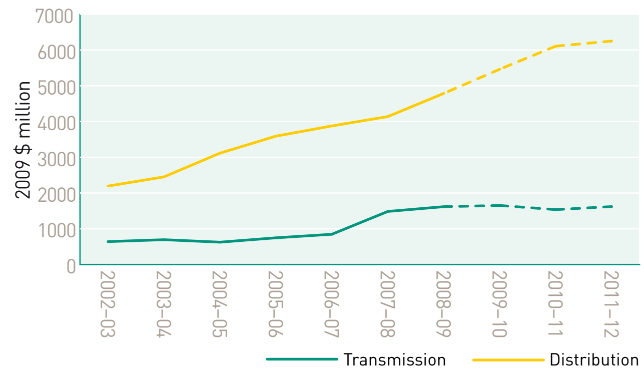
> the global financial crisis has significantly increased debt financing costs for all networks. The rate of return on capital in the next regulatory periods has thus increased by more than 100 basis points compared with the rate in previous periods. Recent AER determinations reflected that higher debt costs increased the revenue requirements of distribution businesses by between 5 and 9 per cent from requirements in previous regulatory periods.

Differences in operating environments can result in significant variations in capital investment requirements (figure 2.4). Electricity distribution investment over the current five year regulatory periods is expected to exceed investment in the previous regulatory periods by around 25–33 per cent in Queensland, 42–103 per cent in New South Wales, 33–59 per cent in Victoria, 88 per cent in South Australia and 69 per cent in the ACT (in real terms).

Differing capital requirements across the networks contribute to different retail impacts on consumers. The *Market overview* in this report comments on the retail impacts of recent AER determinations.

On an annual basis, transmission investment in the NEM totalled around $1.6 billion in 2008–09 and was forecast to remain at this level to 2011–12 (figure 2.5). Distribution investment was almost $4.5 billion in 2008–09 and is expected to rise to over $6 billion in 2011–12.

Figure 2.5
Total electricity network investment



Notes:

Actual data (unbroken lines) are used where available; forecast data (broken lines) are used for other years.

Transmission investment excludes private interconnectors.

All data are converted to June 2009 dollars.

Sources: Regulatory determinations by the AER and OTTER (Tasmanian distribution).

2.5 Operating and maintenance expenditure

The AER determines allowances for each network to cover efficient operating and maintenance expenditure. The needs of a network depend on load densities, the scale and condition of the network, geographic factors and reliability requirements.

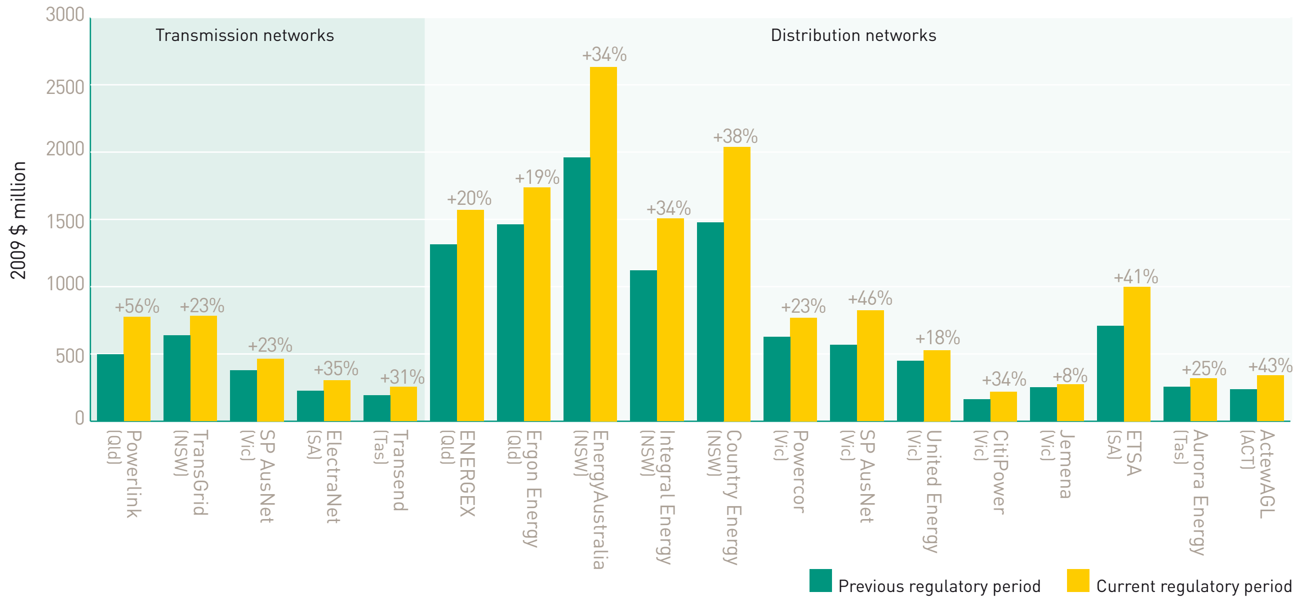
Figure 2.6 illustrates operating expenditure allowances for electricity networks in the current five year regulatory periods compared with previous regulatory periods. In the current five year cycle, transmission businesses will each spend, on average, around $100 million per year on operating and maintenance costs. In distribution, operating costs per business are forecast at around $200 million per year.

Overall, real expenditure allowances are rising over time, in line with rising demand and costs. On average, real operating and maintenance costs are forecast to rise by around 34 per cent in transmission and 30 per cent in distribution over the current five year regulatory periods.

Differences in the networks' operating environments (outlined in section 2.4.1) resulted in significant variations in expenditure allowances. Under determinations made in 2010 for the distribution sector, operating and maintenance expenditure is projected to rise in the current regulatory cycle by around 19 per cent in Queensland, 27 per cent in Victoria and 41 per cent in South Australia (in real terms) (figure 2.6). The *Market overview* in this report comments on the retail impacts of the determinations.

In assessing operating expenditure forecasts, the AER considers relevant cost drivers, including load growth, expected productivity improvements, and changes in real input costs for labour and materials. The recent Victorian determinations, for example, accounted for an expected increase in regulatory compliance costs

Figure 2.6
Operating expenditure of electricity networks



Note: Current regulatory period expenditure are forecasts in regulatory determinations.

Sources: Regulatory determinations by the AER and OTTER (Tasmanian distribution).

for electrical safety, network planning and customer communications, largely stemming from changes associated with the 2009 Victorian bushfires.

2.5.1 Efficiency benefit sharing schemes

The AER operates incentive schemes for businesses to make efficient operating and maintenance expenditure in running their networks. The schemes allow a business to retain efficiency gains (and to bear the cost of any efficiency losses) for five years after the gain (loss) is made. In the longer term, the businesses share efficiency gains or losses with customers through price adjustments.

A benchmark level of expenditure determines the level of efficiency gains or losses. Under the incentive schemes, the businesses retain around 30 per cent of efficiency gains or losses against the benchmark, and pass on the remaining 70 per cent to customers through price adjustments.

The incentive schemes apply to all transmission networks and the Queensland and South Australian distribution networks. They will apply to the Victorian distribution networks from 1 January 2011, and to other networks from the start of their next regulatory periods.

2.6 Network quality of service

Reliability (the continuity of energy supply to customers) is the main barometer of service for an electricity network. 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 electricity supply to be unexpectedly disconnected. They may result from operational error, asset overload or deterioration, or routine external causes such as damage caused by extreme weather, trees, birds, possums, vehicle impacts or vandalism. Reliability issues may be ongoing if part of a network has inadequate maintenance or is used near its capacity limits at times of peak demand. These factors sometimes occur in combination.

While a serious transmission network failure may require the power system operator to disconnect some customers (known as load shedding), most power outages result from reliability issues with the distribution network. Distribution outages account for over 90 per cent of the duration of all electricity outages in the NEM.[8]

A reliable network keeps electricity outages to efficient levels rather than trying to eliminate every possible interruption. An efficient outcome requires assessing the value of reliability to the community (measuring the impact on services) and the willingness of customers to pay.

2.6.1 Transmission network reliability

The quality of transmission network services relates principally to network reliability and network congestion. The following section considers network reliability, while section 2.7 considers network congestion issues.

Transmission networks are designed to deliver high rates of reliability. They are generally engineered and operated with sufficient capacity to act as a buffer against planned and unplanned interruptions in the power system.

Energy Supply Association of Australia data indicate the NEM jurisdictions have generally achieved high rates of transmission reliability. In 2008–09 total unsupplied energy in Victoria totalled 7.5 minutes—up from less than one minute in the previous year. Tasmania has continued to record improved transmission reliability, with 1.83 minutes of unsupplied energy in 2008–09. Unsupplied energy in New South Wales and South Australia has remained low.

The AER's national service target performance scheme provides incentives for transmission businesses to maintain or improve network performance. It acts as a counterbalance to the efficiency benefit sharing scheme (section 2.5.1) so businesses do not reduce costs at the expense of service quality. The scheme sets performance targets on:

> transmission circuit availability
> the average duration of transmission outages
> the frequency of 'off supply' events.

The transmission network scheme also includes a component based on the market impact of transmission congestion (section 2.7.2).

Rather than impose a common benchmark target on all transmission networks, the AER sets separate standards that reflect the circumstances of each network based on its past performance. Under the scheme, the over- or underperformance of a network against its targets results in a gain (or loss) of up to 1 per cent of its regulated revenue.

The results are standardised for each network to derive an 's-factor' that can range between –1 (the maximum penalty) and +1 (the maximum bonus). Table 2.3 sets out the s-factors for each network for the past six years.

The major networks in eastern and southern Australia have generally outperformed their targets. The only businesses to receive a financial penalty in 2009 were TransGrid (New South Wales), for the second half of the year, and Directlink.

2.6.2 Distribution network reliability

The trade-offs between improved reliability and cost mean the standards for distribution networks are less stringent than those for generation and transmission. These less stringent standards also reflect that the impact of a distribution outage tends to be localised to part of the network, compared with the potentially widespread geographic impact of a generation or transmission outage. The capital intensive nature of distribution networks makes it expensive to build in high levels of redundancy (spare capacity) to improve reliability. These factors help to explain why distribution outages account for such a high proportion of electricity outages in the NEM.

The most frequently used indicators of distribution network reliability in Australia are the system average interruption duration index (SAIDI) and the system

8 See AER, *State of the energy market 2007*, 'Essay B', 2007, pp. 38–53.

Table 2.3 S-factor values

	2004	2005	2006	2007	2008		2009	
Powerlink (Qld)				0.82		0.53		0.20
TransGrid (NSW)	0.93	0.70	0.63	–0.12		0.31	0.20	–0.30
EnergyAustralia (NSW)	1.00	0.67	0.39	–0.14		0.72		0.37
SP AusNet (Vic)	0.22	0.09	–0.17	0.06	0.15	0.82		0.50
ElectraNet (SA)	0.63	0.71	0.59	0.28	0.29	–0.40		0.60
Transend (Tas)	0.55	0.19	0.06	0.56		0.85	0.90	0.10
Directlink (Qld–NSW)			–0.54	–0.62		–1.00		–1.00
Murraylink (Vic–SA)			0.21	–0.32		0.69		0.90

Notes:

SP AusNet reported separately for the first quarter of 2008 and the remainder of the year.

ElectraNet reported separately for the first and second halves of 2008.

TransGrid and Transend reported separately for the first and second halves of 2009. EnergyAustralia data for 2009 is for the six months to June.

In 2008 SP AusNet transitioned to a new regulatory control period, with the financial incentive capped at +1 per cent of its maximum allowable revenue. Its financial incentive in previous regulatory control periods was capped at +0.5 per cent.

Source: AER, *Transmission network service providers: electricity performance report for 2008–09*, 2010.

average interruption frequency index (SAIFI). The indicators relate to the average duration and frequency of network interruptions and outages. They do not distinguish between the nature and size of loads affected by supply interruptions.

Table 2.4 estimates historical data on the average duration (SAIDI) and frequency (SAIFI) of outages experienced by distribution customers. The 'Market overview' in this report presents SAIDI data in graphical form.

The SAIDI and SAIFI data include outages that originate in the generation and transmission sectors. From a customer perspective, the unadjusted data presented here are relevant, but an assessment of network performance should normalise data to exclude interruption sources beyond the network's reasonable control.

A number of issues limit the validity of comparing reliability data across jurisdictions. In particular, the data rely on the accuracy of the businesses' information systems, which may vary considerably. Design, geographic conditions and historical investment also differ across the networks.

Noting these caveats, the SAIDI data indicate electricity networks in the NEM have delivered reasonably stable reliability outcomes over the past few years. Across the NEM, a typical customer experiences around 200–250 minutes of outages per year, but with significant regional variations.

The average duration of outages per customer rose in most jurisdictions in 2008–09. Queensland customers experienced the largest increase, with the average outage duration rising by more than 100 minutes. The rise was largely the result of storm activity, but Ergon Energy also noted that changed maintenance practices contributed to the outcome. Queensland experiences significant variations in performance, partly because its large and widely dispersed rural networks make it more vulnerable to outages than are other NEM jurisdictions.

Extreme weather events contributed to load shedding and network failures in Victoria during the summer 2009 heatwave and bushfires. Even after adjusting for excluded events, Victoria in 2008–09 experienced its highest rate of outages in a decade. Extreme weather was also a factor in New South Wales, although equipment faults and human error were responsible for failures in EnergyAustralia's subtransmission network.

Table 2.4 **System average interruption duration index (SAIDI) and frequency index (SAIFI)**

	2000–01	2001–02	2002–03	2003–04	2004–05	2005–06	2006–07	2007–08	2008–09
SAIDI (MINUTES)									
Queensland	314	275	265	434	283	351	233	264	365
New South Wales	175	324	193	279	218	191	211	180	211
Victoria	152	151	161	132	165	165	197	228	255
South Australia	164	147	184	164	169	199	184	150	161
Tasmania	265	198	214	324	314	292	256	304	252
NEM weighted average	**198**	**245**	**199**	**258**	**211**	**221**	**211**	**213**	**254**
SAIFI (NUMBER OF INTERRUPTIONS)									
Queensland	3.0	2.8	2.7	3.4	2.7	3.1	2.1	2.4	2.9
New South Wales	2.5	2.6	1.4	1.6	1.6	1.8	1.9	1.7	1.8
Victoria	2.0	2.0	2.2	1.9	1.8	1.9	2.1	1.7	2.5
South Australia	1.7	1.6	1.8	1.7	1.7	1.9	1.8	1.5	1.5
Tasmania	2.8	2.3	2.4	3.1	3.1	2.9	2.6	2.6	1.9
NEM weighted average	**2.4**	**2.4**	**2.0**	**2.2**	**1.9**	**2.1**	**2.0**	**1.9**	**2.2**

Notes:

The data reflect total outages experienced by distribution customers, including outages resulting from issues in the generation and transmission sectors. In general, the data have not been normalised to exclude outages beyond the network operator's reasonable control. Some data have been adjusted to remove the impact of natural disasters (for example, Cyclone Larry in Queensland and extreme storm activity in New South Wales), which would otherwise have severely distorted the data.

The NEM averages are weighted by customer numbers.

Victorian data are for the calendar year beginning in that period.

Sources: Performance reports by the AER (Victoria), the QCA (Queensland), ESCOSA (South Australia), OTTER (Tasmania), the ICRC (ACT), EnergyAustralia, Integral Energy and Country Energy. Some data are AER estimates derived from official jurisdictional sources. The AER consulted with PB Associates when developing historical data.

The SAIFI data show the average frequency of outages has been relatively stable since 2002–03, with distribution customers across the NEM experiencing outages around twice a year. The average frequency of outages rose in 2008–09, driven mainly by poorer outcomes in Queensland and Victoria.

2.6.3 Customer service—distribution networks

The monitoring of service quality for electricity distribution networks typically includes assessing customer service. Network businesses report on their responsiveness to issues, including the timely connection of services, call centre performance and customer complaints.

Table 2.5 provides a selection of customer service data for the networks. Performance in 2008–09 broadly aligned with that of previous years.

2.6.4 Distribution service performance incentive schemes

Jurisdictions operate guaranteed service level (GSL) schemes that provide for payments to customers that experience poor service. The schemes are intended not to provide legal compensation to customers, but to enhance the service performance of distribution businesses.

Jurisdictional GSL schemes provide payments for poor service quality in areas such as streetlight repair, the frequency and duration of supply interruptions, new connections and notice of planned interruptions. Under most of the jurisdictional schemes, the majority of GSL payments in 2008–09 related to the duration and frequency of supply interruptions exceeding specified limits. Payments in Queensland resulted mainly from late connections, while New South Wales networks also made significant payments for not providing sufficient notice of planned network interruptions.

Table 2.5 Timely provision of service by electricity distribution networks

NETWORK	PERCENTAGE OF CONNECTIONS COMPLETED AFTER AGREED DATE					PERCENTAGE OF CALLS ANSWERED BY HUMAN OPERATOR WITHIN 30 SECONDS				
	2004–05	2005–06	2006–07	2007–08	2008–09	2004–05	2005–06	2006–07	2007–08	2008–09
QUEENSLAND[1]										
ENERGEX	3.98	0.62	0.55	10.79	2.54	89.4	89.4	79.1	96.3	89.7
Ergon Energy	6.62	0.84	0.49	0.72	0.30	85.0	85.1	87.0	86.2	87.2
NEW SOUTH WALES[2]										
EnergyAustralia	0.01	0.02	0.02	0.01	0.01	44.6	81.3	74.3	81.1	79.7
Integral Energy	0.01	0.02	0.02	0.01	0.01	81.0	89.0	70.9	96.2	92.0
Country Energy	0.02	0.02	0.02	0.01	0.01	48.4	47.2	…	61.4	51.4
ActewAGL	…	…	…	…	…	65.6	39.7	62.4	70.5	…
VICTORIA[3]										
Powercor	0.12	0.06	0.04	0.02	0.01	88.7	86.7	89.4	90.0	86.6
SP AusNet	0.21	2.40	2.66	1.74	2.58	82.7	92.3	91.2	92.3	91.6
United Energy	0.05	0.29	0.05	0.08	0.12	73.8	72.9	74.0	73.0	73.1
CitiPower	0.02	0.03	0.05	0.01	0.00	89.2	85.7	87.2	87.8	82.0
Jemena	0.12	0.09	0.19	0.8	0.89	75.2	77.4	79.9	73.1	77.4
SOUTH AUSTRALIA[1]										
ETSA Utilities	0.91	1.33	0.51	1.30	0.58	86.9	85.2	89.3	88.7	88.5
TASMANIA										
Aurora Energy	…	0.15	0.14	2.00	1.77	…	…	…	…	…

1. Completed connections data for Queensland and South Australia include new connections only.
2. New South Wales completed connections data from 2005–06 are state averages.
3. Victorian data are for the calendar year beginning in that period.

Sources: Distribution network performance reports by the AER (Victoria), IPART (New South Wales), the QCA (Queensland), ESCOSA (South Australia), OTTER (Tasmania) and the ICRC (ACT). Some data are AER estimates derived from official jurisdictional sources.

As for transmission, the AER has developed a national incentive scheme to encourage distribution businesses to maintain or improve service performance. The scheme focuses on supply reliability (the frequency and duration of network outages) and customer service. The distribution scheme includes a GSL component, under which customers are paid directly if performance falls below threshold levels. The GSL component does not apply if the distribution business is subject to jurisdictional GSL obligations. Victoria will be the first jurisdiction to apply the GSL component of the national scheme (from 1 January 2011).

The national scheme generally provides financial bonuses and penalties of up to 5 per cent of revenue to network businesses that meet (or fail to meet) performance targets.[9] The results are standardised for each network to derive an 's-factor' that reflects deviations from target performance levels. While the scheme should be consistent nationally where practical, it has some flexibility to allow for transitional issues and the differing circumstances and operating environments of each network.

The national scheme currently applies to the Queensland and South Australian networks and as a paper trial in New South Wales and the ACT (that is, targets are set but no financial penalties or rewards apply). It will apply to all other networks from the start of their next regulatory periods.

9 Queensland network businesses face financial bonuses and penalties of up to 2 per cent of revenue.


Mark Wilson

2.7 Electricity transmission congestion

Transmission networks do not have unlimited capacity to carry electricity from one location to another. Physical limits are imposed on the amount of power that can flow over any part or region of a network, to avoid damage and ensure stability during small disturbances.

Some transmission congestion results from factors within the control of a service provider—for example, the provider's scheduling of outages, its maintenance and operating procedures and its standards for network capability (such as thermal, voltage and stability limits). Factors beyond the control of the service provider include extreme weather—for example, hot weather can result in high air conditioning loads that push a network towards its pre-determined limits. Typically, most congestion costs accumulate on just a few days, and are largely attributable to network outages.

If a major transmission outage occurs in combination with other generation or demand events, it can cause the load shedding of some customers. This scenario is rare in the NEM, however. Rather, the main impact of congestion is on the cost of producing electricity. In particular, transmission congestion increases the total cost of electricity by displacing low cost generation with more expensive generation.

Congestion can also create opportunities for the exercise of market power. If a network constraint prevents generators from moving electricity to customers, then there is less competition in the market.

In addition to the direct economic cost of using more expensive generation to meet demand, congestion can create risks for participants and promote behaviour that may inhibit economic efficiency. This behaviour can include 'disorderly bidding', whereby a generator tries to ensure dispatch by bidding its capacity at prices that do not reflect underlying costs.

2.7.1 Measuring transmission congestion

AEMO is developing a Congestion Information Resource (CIR) to provide information on patterns of congestion and expected market outcomes. It released an interim resource in March 2010, and aimed to release the first full CIR by September 2011.

As part of this process, AEMO compiles data on the extent and pattern of 'mispricing'. Mispricing occurs when network congestion causes a generator to be constrained on or off.[10] The data measure the additional cost of dispatching energy as a result of congestion.

Figure 2.7 indicates the extent of mispricing in the NEM over the past two years. The data illustrate the number of mispriced connection points (between generators and the transmission network) in each region, and the average duration of mispricing per connection point. While the number of mispriced connection points remained relatively stable in each region, the duration of mispricing fluctuated significantly. In 2009–10 Queensland experienced both a greater number of mispriced connection points and a longer average duration of mispricing, compared with other jurisdictions.

2.7.2 Reducing congestion costs

Recognising the significance of congestion costs, the AER has provided for rising transmission investment in regulatory decisions to increase network capacity (section 2.4.1), and in 2008 introduced an incentive scheme to reduce congestion.

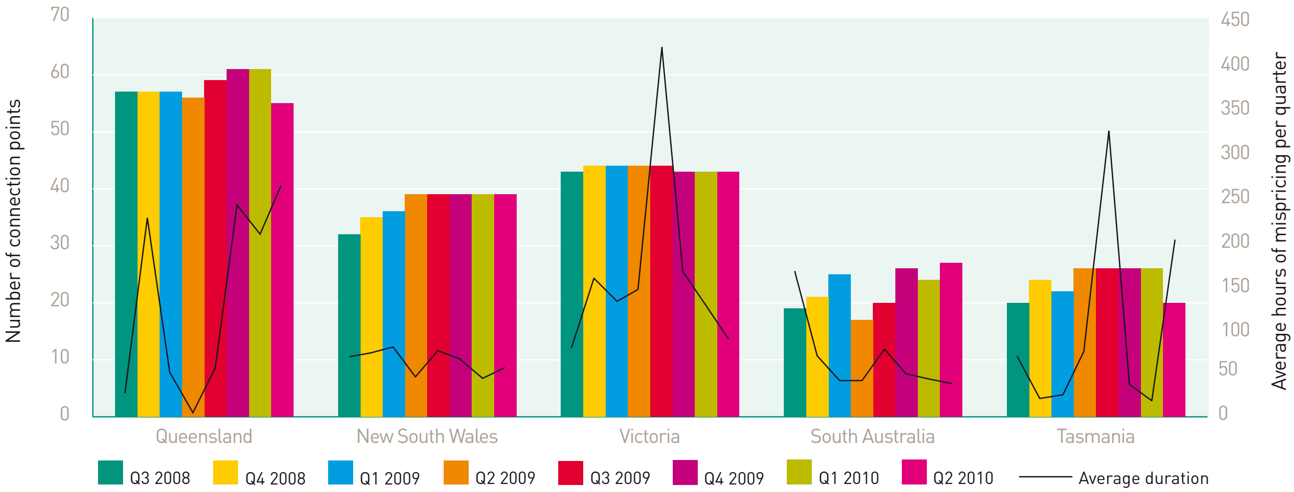
The incentive mechanism forms part of the service performance incentive scheme and aims to encourage network owners to account for the impact of their behaviour on the market.[11] It operates as a bonus-only scheme and rewards network owners for improving operating practices such as outage timing and notification, the minimising of outage impact on network flows—for example, by conducting live line work, maximising line ratings and reconfiguring

10 A generator is 'constrained on' if it is required to be dispatched despite offering to supply energy at above the market price. A generator is 'constrained off' if it has offered to supply energy below the market price, but cannot be dispatched because the network is congested.

11 AER, *Electricity transmission network service providers: service target performance incentive scheme,* 2008.

Figures 2.7

Number of mispriced connection points and the average duration of mispricing per connection point



Source: AEMO.

the network—and equipment monitoring. In some cases, these improvements may be more cost-efficient solutions to reduce congestion than those requiring investment in infrastructure.

The mechanism permits a transmission business to earn an annual bonus of up to 2 per cent of its revenue if it can eliminate all outage events with a market impact of over $10 per megawatt hour.[12]

Only TransGrid and Powerlink participate in the scheme; ElectraNet will participate in 2011. In its first compliance period (1 July 2009 – 31 December 2009), TransGrid reduced material outage events by 20 per cent from its benchmark, and earned incentive payments of $1.3 million.

2.7.3 Interregional congestion

Congestion in transmission interconnectors can cause wholesale electricity prices to differ across the regions of the NEM. In particular, prices may spike in a region that is constrained in its ability to import electricity.

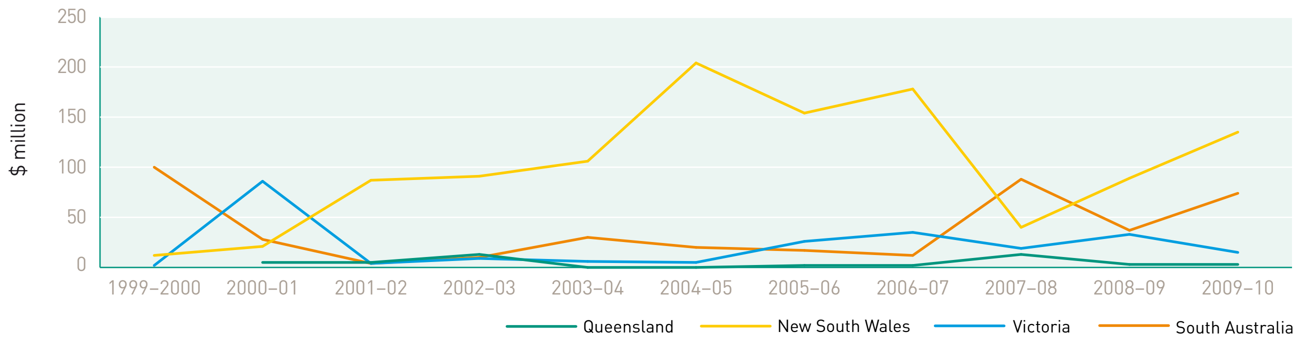
To the extent that trade is possible, electricity generally flows from lower to higher price regions. When trade occurs, the exporting generators are paid at their local regional spot price, while importing retailers must pay the (typically higher) spot price in their region. The difference between the price paid in the importing region and the price received in the generating region, multiplied by the amount of flow, is called a settlement residue. The volume of settlement residues indicates the extent of interregional congestion.

Figure 2.8 charts the annual accumulation of interregional settlement residues in each region. There is some volatility in the data, given a complex range of factors can contribute to price separation—for example, the availability of transmission interconnectors and generation plant, weather conditions and the bidding behaviour of generators.

New South Wales typically records the highest level of settlement residues. The level reflects the region's status as the largest importer of electricity (in dollar and volume terms) in the NEM, which can make it vulnerable to price separation events. Residues accruing to South Australia rose over the past three years, reflecting higher spot prices in the region (particularly over summer). As net exporters, Queensland and Victoria tend to accumulate modest settlement residues.

12 The performance improvement required for the full 2 per cent bonus may be unrealistic. A realistic level of performance may be difficult to determine until the scheme has been in place for some time.

Figure 2.8
Settlement residues in the National Electricity Market



Source: AEMO.

2.8 Policy developments for electricity networks

In July 2009 AEMO began operating as a single, industry funded national energy market operator for both electricity and gas. It has a National Transmission Planner (NTP) role, overlaying the traditional jurisdiction based approach to network planning with a national, long term focus on efficiently developing the transmission grid.

AEMO expected to publish its first annual national transmission network development plan in December 2010, outlining its view of the efficient development of the power system over the next 20 years. The plan details network and non-network investment needs based on a range of demand growth and generation investment scenarios.

The plan will inform AER network revenue determinations. Transmission businesses and jurisdictional planning bodies will use the plan to develop annual planning reports, conduct RIT-T analyses and assess scale efficient network extensions (section 2.8.2).

In addition to this annual planning role, AEMO reviews major network development opportunities—for example, in 2010 AEMO (with ElectraNet) undertook a feasibility study of options to increase the interconnector transfer capability between South Australia and other NEM load centres.[13] The study aimed to identify options to expand the development of South Australia's renewable and other energy resources.

2.8.1 Climate change (review of energy market frameworks)

The AEMC in 2009 completed a review of the likely impacts of climate change policies on energy market frameworks. Following that review, a number of changes to the market framework are being progressed.

Interregional transmission charging

In February 2010 the Ministerial Council on Energy (MCE) submitted a rule change to implement new interregional charging arrangements for transmission businesses. This change is designed to promote more efficient operation of, and investment in, transmission networks.

Under current arrangements, a transmission network business recovers its costs from customers within its region. Customers in an importing region, therefore, do not pay the transmission costs incurred in the exporting region to serve their load. The rule change introduces a load export charge that effectively treats the transmission business in the importing region as a

13 Interconnectors between South Australia and Victoria have a history of congestion, especially during peak demand. South Australia's increasing reliance on wind generation has aggravated this issue.

customer of the transmission business in the exporting region. All network charges will be ultimately recovered from the network's customers.

Scale efficient network extensions

While electricity networks historically developed around the location of coal fired generators, new investment in renewable generation is likely to cluster in locations that are remote from customers and networks. In February 2010 the MCE submitted a rule change to promote the efficient connection of clusters of new generation. The framework aims to take advantage of economies of scale in network assets and avoid the inefficient duplication of connection assets.

Under the proposed approach, AEMO would identify geographic zones in which generation expansion is likely. Network businesses would then develop extension options to accommodate anticipated future generation capacity. Construction would occur once a connecting generator accepts an option.

Generators would pay their share of the connection asset that they use, with customers underwriting the risk of asset stranding or delays in connection. The AER would have a role in protecting consumers' interests, with powers to disallow any project that it considers does not meet the requirements of the scheme.

The AEMC published an options paper in September 2010 testing the proposal against alternative solutions. It expects to make a draft determination in February 2011.

Transmission frameworks review

The AEMC in 2010 was reviewing arrangements for the provision and use of electricity transmission services, and implications for the market frameworks governing network services in the NEM. It was examining:

> the extent to which appropriate financial incentives ensure efficient and timely provision of transmission services
> the extent to which the transmission planning framework effectively aligns with the regulatory process for transmission investment
> whether network businesses have sufficient financial incentives to operate their networks in a manner that optimises overall network availability and market efficiency
> mechanisms that may promote more efficient bidding and pricing behaviour by generators in congested parts of the network
> the effectiveness of network charging and access arrangements, including the impacts on generator investment
> options to improve locational signals for generators.

A consultative committee made up of energy market stakeholders was established to assist the review. The final report is expected by November 2011.

2.9 Demand management and metering

Demand management (or demand-side participation) relates to strategies to manage the growth in overall or peak demand for energy services. The objective is to reduce or shift demand, or implement efficient alternatives to network augmentation. Such strategies are implemented typically at the distribution or retail level, and require cooperation between energy suppliers and customers.

In distribution regulation, the AER applies demand management schemes with incentives for businesses to implement efficient non-network approaches to manage demand. The schemes fund projects or initiatives that reduce network demand. In some jurisdictions, the schemes also allow businesses to recover revenue forgone as a result of successful demand reduction initiatives. No business is compelled to take up the scheme, with the allowance provided on a 'use it or lose it' basis. The AER has developed demand management schemes for New South Wales and the ACT, South Australia and Queensland, and Victoria.

The AEMC, in its review of the impact of climate change policies on energy market frameworks, recommended expanding the allowance to cover innovations in connecting generators to distribution networks.

2.9.1 Metering and smart grids

Meters record the energy consumption of customers at their point of connection to the distribution network. Effective metering, when coupled with appropriate price signals, can encourage customers to more actively manage their electricity use. Both the Australian and state governments are implementing plans to introduce smart meters with communication capabilities that allow for remote meter reading and the connection and disconnection of customers.

The Council of Australian Governments (COAG) has committed to the progressive rollout of smart meters in jurisdictions where the benefits outweigh costs. Development of a framework to support rolling out smart electricity meters in the NEM was continuing in 2010.

The Victorian Government has initiated a program, outside the COAG process, to provide smart meters to all customers over four years from 2009. Despite the rollout, the Victorian Government has imposed a moratorium on the introduction of time-of-use tariffs for customers.[14]

In October 2009 the AER released a final determination on metering services budgets for 2009–11 and charges for 2010 and 2011.[15] It amended this determination in January 2010 following an appeal to the Australian Competition Tribunal. Smart meter costs began to be passed on to Victorian customers from 1 January 2010, with network charges increasing on average by almost $70. A further increase of around $8 is expected in 2011.

In addition to the smart meter developments, the Australian Government has implemented a $100 million Smart Grid, Smart City initiative to support the installation of Australia's first commercial scale smart grid. The initiative will be based in Newcastle, New South Wales. It will explore options to connect additional renewable and distributed energy and hybrid vehicles to the grid; provide customers with improved energy use information, automation and savings; and improve network reliability.

14 If the customer consumes less than 20 megawatt hours of electricity per year.
15 AER, *Victorian advanced metering infrastructure review—2009–11 AMI budget and charges applications, final determination*, 2009.