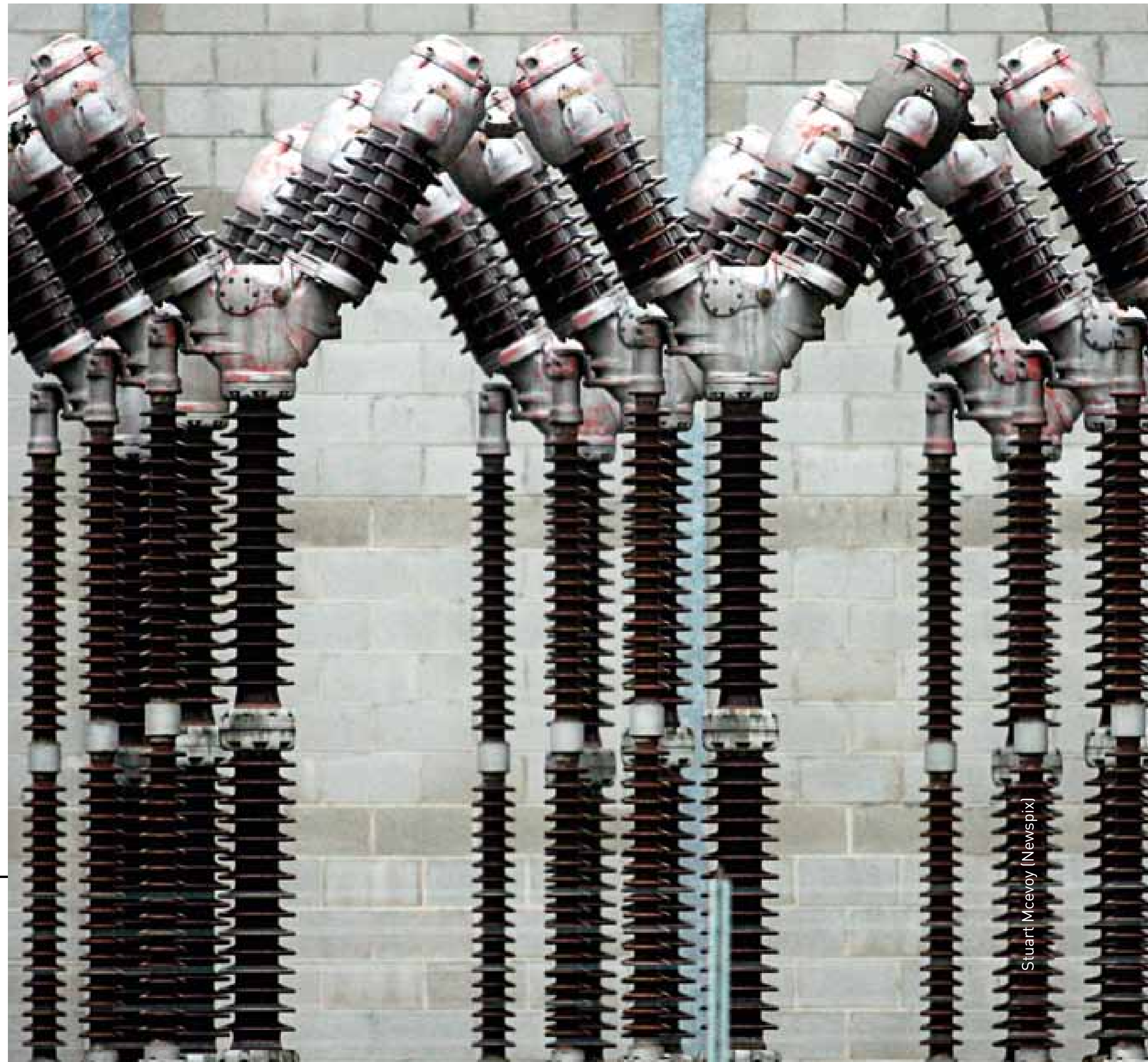


Stuart Mcevoy (Newspix)

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

The National Electricity Market (NEM) in eastern and southern Australia provides a fully interconnected transmission 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. There are five state based transmission networks, with cross-border interconnectors linking the grid (table 2.1).

The NEM has 13 major electricity distribution networks (table 2.2). Queensland, New South Wales and Victoria each have multiple networks that are monopoly providers within designated areas. The ACT, South Australia and Tasmania each have 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—18 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 distribution network (ActewAGL) has joint government and private ownership. All networks (transmission and distribution) in Queensland, New South Wales and Tasmania are government owned.

Aside from state and territory governments, the principal network owners at June 2011 were:

- *Cheung Kong Infrastructure* and *Power Assets Holdings*, which jointly 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*, which 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 or have equity in a number of gas networks (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) plans and directs network augmentation. AEMO also buys bulk network services from SP AusNet for sale to customers.

In some jurisdictions, ownership links exist between electricity networks and other segments of the electricity sector. In Tasmania and the ACT,[1] 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 the state owned Ergon Energy continues to provide both distribution and retail services.

1 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), 2009–10	MAXIMUM DEMAND (MW), 2009–10	ASSET BASE (2010 $ MILLION)[1]	INVESTMENT—CURRENT PERIOD (2010 $ MILLION)[2]	CURRENT REGULATORY PERIOD	OWNER
NEM REGION NETWORKS								
Powerlink	Qld	13 569	49 593	8 891	4 100	2 642	1 July 2007 – 30 June 2012	Queensland Government
TransGrid	NSW	12 656	72 814	14 051	4 346	2 541	1 July 2009 – 30 June 2014	New South Wales Government
SP AusNet	Vic	6 553	50 925	9 858	2 291	806	1 Apr 2008 – 30 Mar 2014	Publicly listed company (Singapore Power International 51%)
ElectraNet	SA	5 591	13 266	3 408	1 372	816	1 July 2008 – 30 June 2013	Powerlink (Queensland Government), YTL Power Investment, Hastings Utilities Trust
Transend	Tas	3 469	11 658	2 366	981	625	1 July 2009 – 30 June 2014	Tasmanian Government
NEM TOTALS		**41 838**	**198 256**		**13 090**	**7 430**		
INTERCONNECTORS[3]								
Directlink (Terranora)	Qld–NSW	63		180	136		1 July 2005 – 30 June 2015	Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)
Murraylink	Vic–SA	180		220	124		1 Oct 2003 – 30 June 2013	Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)
Basslink	Vic–Tas	375			884[4]		Unregulated	Publicly listed 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 2010 dollars.
2. Investment data are forecast capital expenditure over the current regulatory period, converted to June 2010 dollars.
3. 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.
4. 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 2009-10*; regulatory determinations by the AER.

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 the network when it was first regulated, plus subsequent new investment, less depreciation. 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 $44 billion—more than three times the valuation for transmission infrastructure (around $13 billion).

Table 2.2 **Electricity distribution networks**

NETWORK	CUSTOMER NUMBERS	LINE LENGTH (KM)	MAXIMUM DEMAND (MW), (2009–10)	ASSET BASE (2010 $ MILLION)[1]	INVESTMENT —CURRENT PERIOD (2010 $ MILLION)[2]	CURRENT REGULATORY PERIOD	OWNER
QUEENSLAND							
Energex	1 298 790	53 256	4 817	7 867	5 783	1 Jul 2010 – 30 Jun 2015	Qld Government
Ergon Energy	680 095	146 000	2 608	7 149	5 113	1 Jul 2010 – 30 Jun 2015	Qld Government
NEW SOUTH WALES AND ACT							
AusGrid[3,4]	1 605 635	49 442	5 609	8 688	8 579	1 Jul 2009 – 30 Jun 2014	NSW Government
Endeavour Energy[3]	866 724	33 817	3 697	3 803	3 052	1 Jul 2009 – 30 Jun 2014	NSW Government
Essential Energy[3]	801 913	190 844	2 239	4 451	4 277	1 Jul 2009 – 30 Jun 2014	NSW Government
ActewAGL	157 635	4 858	604	617	314	1 Jul 2009 – 30 Jun 2014	ACTEW Corporation (ACT Government) 50%; Jemena (Singapore Power International) 50%
VICTORIA							
Powercor	706 577	84 027	2 362	2 189	1 550	1 Jan 2011 – 31 Dec 2015	Cheung Kong Infrastructure/ Power Assets Holdings 51%; Spark Infrastructure 49%
SP AusNet	623 307	48 259	1 774	2 052	1 465	1 Jan 2011 – 31 Dec 2015	SP AusNet (listed company; Singapore Power International 51%)
United Energy	634 508	12 628	2 016	1 365	877	1 Jan 2011 – 31 Dec 2015	Jemena (Singapore Power International) 34%; DUET Group 66%
CitiPower	308 203	6 506	1 354	1 273	821	1 Jan 2011 – 31 Dec 2015	Cheung Kong Infrastructure/ Power Assets Holdings 51%; Spark Infrastructure 49
Jemena	309 505	5 971	958	748	468	1 Jan 2011 – 31 Dec 2015	Jemena (Singapore Power International)
SOUTH AUSTRALIA							
ETSA Utilities	817 300	87 220	2 981	2 772	2 154	1 Jan 2011 – 31 Dec 2015	Cheung Kong Infrastructure/ Power Assets Holdings 51%; Spark Infrastructure 49%
TASMANIA							
Aurora Energy	271 750	24 385	1 042	1 105	650	1 Jan 2008 – 30 Jun 2012	Tas Government
NEM TOTALS	**9 081 942**	**747 213**		**44 079**	**35 103**		

MW, megawatts.

1. Asset valuation is the opening regulated asset base for the current regulatory period, converted to June 2010 dollars.
2. Investment data are forecast capital expenditure over the current regulatory period, converted to June 2010 dollars. The data include capital contributions, which can be significant—for example, 10–20 per cent of investment in Victoria and over 20 per cent in South Australia—but do not form part of the regulated asset base for the network.
3. Following the privatisation of energy retail assets in New South Wales, the network divisions of EnergyAustralia, Integral Energy and Country Energy were rebranded as AusGrid, Endeavour Energy and Essential Energy respectively.
4. AusGrid's distribution network includes 962 kilometres of transmission assets that are treated as distribution assets for the purpose of economic regulation and performance assessment.

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), AusGrid, Essential Energy and Endeavour Energy.

2.2 Economic regulation of electricity networks

Energy networks are capital intensive and incur declining average costs as output increases. This means network services in a particular geographic area can be most efficiently served by a single supplier, 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

The National Electricity Law lays the foundation for the regulatory framework governing electricity networks. In particular, it sets out the National Electricity Objective: to promote efficient investment in, and operation of, electricity services in the long term interest of consumers. It also sets out revenue and pricing principles, including that network businesses should have a reasonable opportunity to recover at least efficient costs.

Regulated electricity network businesses must periodically apply to the AER to assess their revenue requirements (typically, every five years). Chapters 6 and 6A of the National Electricity Rules lay out the framework that the AER must apply in undertaking this role for distribution and transmission networks respectively. The AER's *State of the energy market 2009* report (sections 5.3 and 6.3) provides an overview of the regulatory process.

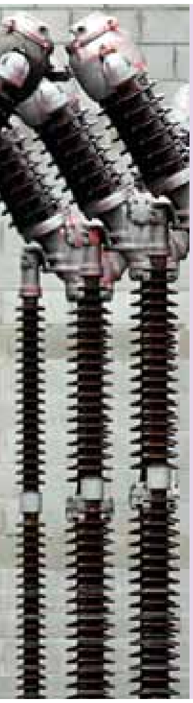
While the regulatory frameworks for transmission and distribution are similar, there are differences. In transmission, the AER must determine a cap on the maximum revenue that a network can earn during a regulatory period. The range of available control mechanisms is wider in distribution, but generally involves setting a ceiling on the revenues or prices that a network can earn or charge during a period. The available mechanisms 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 or maximum revenue caps*, which set a ceiling on revenue that may be recovered during a regulatory period—used for the Queensland and ACT networks, and to be used for the Tasmanian network from 1 July 2012.

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 largest component is the return on capital, which may account for up to two-thirds of revenues. The size of a network's RAB (and projected investment) and its weighted average cost of capital (the rate of return necessary to cover a commercial return on equity and efficient debt costs) both influence the return on capital. An allowance for operating expenditure typically accounts for a further 30 per cent of revenue requirements.

In 2011 the AER reviewed the regulatory framework under chapters 6 and 6A of the Rules to identify whether improvements could be made to better promote efficient investment in, and use of, energy services for the long term interests of consumers. It highlighted deficiencies in the framework, and in September 2011 the AER proposed Rule changes to address these issues (box 2.1 and section A2 of the *Market overview*).



Box 2.1 AER Rule change proposals on regulatory framework

The substantial price impact of some recent determinations led the AER in 2011 to conduct an internal review of the framework in the national energy Rules for setting energy network charges. While the review found many aspects of the framework operate well, several features were leading to consumers paying more than necessary for energy services.

Following its review, the AER in September 2011 submitted Rule change proposals to the Australian Energy Market Commission (AEMC) to address these issues.[2] Section A2 of the *Market overview* discusses the proposals which, in summary, would:

- allow the AER to make holistic and independent assessments of a network's efficient expenditure needs, based on all available information, evidence and data—including benchmarking analysis
- remove incentives for network overinvestment by allowing only 60 per cent of any spending above approved forecasts to be added to a network's asset base
- introduce a common approach to setting the cost of capital for all electricity and gas network businesses; and allow the AER to set cost of capital parameters that reflect current commercial practices
- improve consultation arrangements with stakeholders.

The AEMC began consulting on the proposals in October 2011. It expects to release a draft determination by July 2012, and a final determination by October 2012.

2.2.2 Regulatory timelines and recent AER determinations

Figure 2.2 shows the regulatory timelines for electricity networks in each jurisdiction. In 2011 the AER commenced reviews for Powerlink (Queensland transmission) and Aurora Energy (Tasmania distribution) for the regulatory periods commencing 1 July 2012. It published draft determinations in November 2011.

Table 1 in the *Market overview* provides summary details of AER determinations made since April 2009.

2.2.3 Merits review by the Australian Competition Tribunal

Under the National Electricity Law, network businesses can apply to the Australian Competition Tribunal for review of an AER determination, or a part of it. Network businesses have typically sought review of specific matters in a determination rather than the whole determination.

To have an AER decision overruled, the network business must demonstrate the AER either:

- made an error of fact that was material to the AER's decision
- incorrectly exercised its discretion, having regard to all the circumstances
- made an unreasonable decision having regard to all the circumstances.

If the tribunal finds the AER erred, it will substitute its own decision or remit the matter back to the AER for consideration.

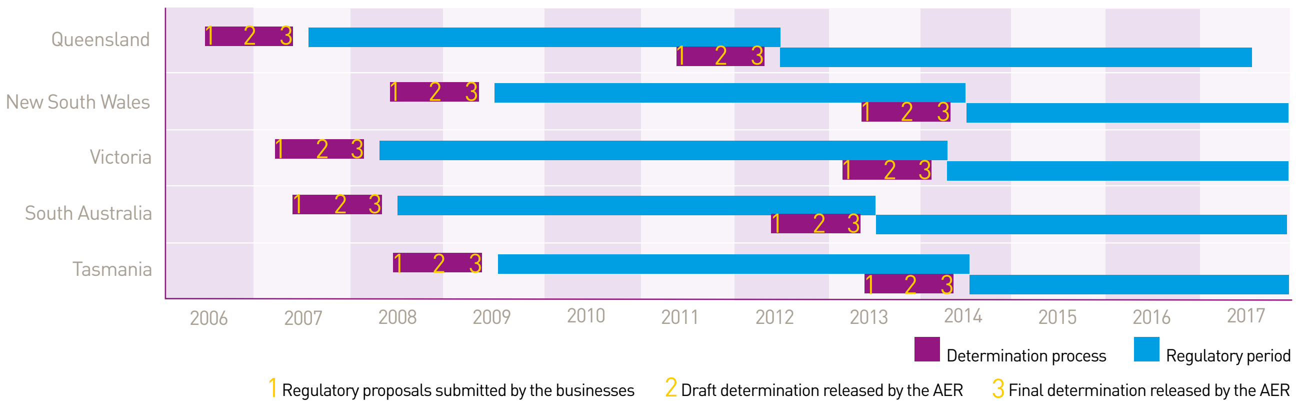
Between June 2008 and October 2011 network businesses sought review of 16 AER determinations on electricity networks—three reviews in transmission and 13 in distribution.[3] Five reviews were continuing in October 2011. The decisions on these reviews have

2 AER, *Rule change proposal, Economic regulation of transmission and distribution network service providers: AER's proposed changes to the National Electricity Rules*, September 2011 (available on the AER and AEMC websites).

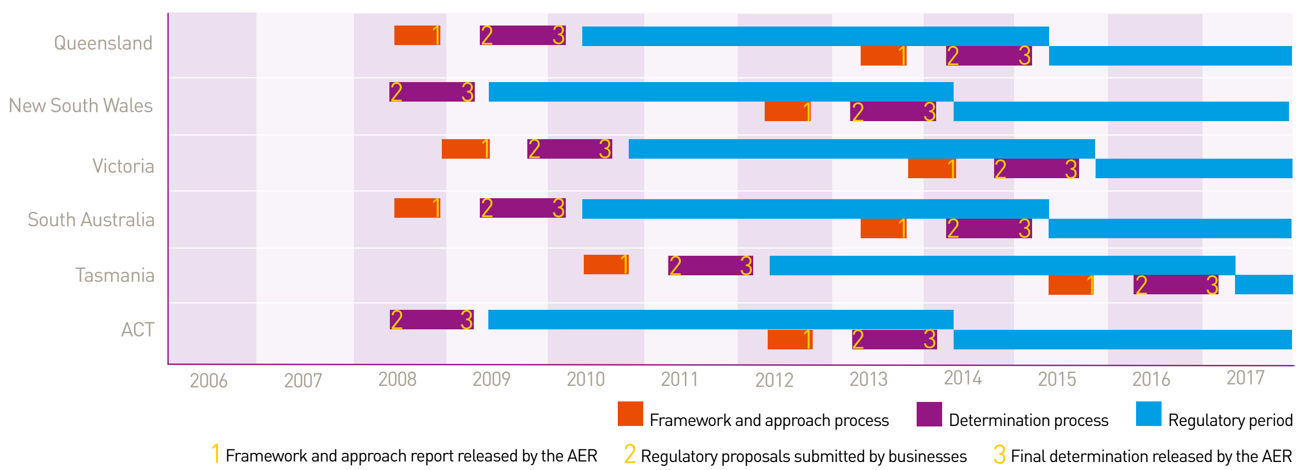
3 Two of the distribution reviews related to charges for advancing metering infrastructure (smart meters) in Victoria. In addition, two determinations have been subject to judicial review under the *Administrative Decisions (Judicial Review) Act 1977* (Cth). At October 2011 the judgment on one matter was reserved.

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.

increased allowable electricity network revenues by around $2.9 billion, with substantial flow-on impacts on retail energy charges. The two most significant contributors to this increase were tribunal decisions on:

- the averaging period for the risk free rate (an input into the weighted average cost of capital)—reviewed for five networks, with a combined revenue impact of $2 billion
- the value adopted for tax imputation credits (gamma), which affects the estimated cost of corporate income tax—reviewed for three networks, with a combined revenue impact of $780 million.

In 2011 the tribunal reviewed AER determinations (made in October 2010) on Victoria's five electricity distribution networks. The matters on which the businesses sought review varied. All sought review of gamma and the debt risk premium that is applied to calculate the cost of capital. Other matters included aspects of approved capital and operating expenditure; the method of escalating the asset base over the regulatory period; and the application of pass through provisions. The tribunal is expected to hand down its decisions in January 2012.

The tribunal also handed down decisions in 2011 on reviews for Energex and Ergon Energy (Queensland) and ETSA Utilities (South Australia). The decisions increased the networks' allowable revenues by around $850 million (a 5 per cent increase in total revenue over the regulatory period). The most significant part of the decision was to lower the value for gamma from 0.65 to 0.25. This change raised the networks' estimated cost of corporate income tax and, consequently, their allowable revenues.

Following the decisions, the Queensland Government intervened to prevent Energex and Ergon Energy from recovering the additional revenue allowance determined by the tribunal. This intervention amounted to a $93 million reduction in the combined revenue forecasts of the businesses in 2011–12 alone.[4]

Table 2 in the *Market overview* summarises outcomes of the tribunal's reviews of AER determinations since 2008.

2.3 Electricity network 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 at almost $58 billion over the current cycle, comprising over $12 billion for transmission and $46 billion for distribution. Average revenues are forecast to rise by around 43 per cent (in real terms) above levels in the previous regulatory periods. The main drivers are higher capital expenditure (investment) and operating costs (discussed in sections 2.4 and 2.5), and higher capital financing costs.

The cost of capital estimates used to determine revenue allowances in the current regulatory periods were higher for all network business than in previous periods. The increase ranged from less than 0.1 percentage points for Powerlink (Queensland transmission) to over 2.6 percentage points for ETSA Utilities (South Australia distribution).

The cost of capital comprises several parameters. The primary parameter underpinning the increases is the debt risk premium, which reflects the cost of borrowing for a business based on its risk of default. Changes and fluctuations in global financial markets have reduced liquidity in debt markets and increased perceptions of risk, pushing up the cost of borrowing. Changes in the risk free rate also affected the determinations.

The tribunal's decision to reduce the value adopted for tax imputation credits (gamma) for the Queensland and South Australian distribution networks also increased revenue allowances (section 2.2.3).

2.4 Electricity network investment

New investment in infrastructure is needed to maintain or improve network performance over time. Investment includes network augmentations (expansions) to meet rising demand and the replacement of ageing assets.

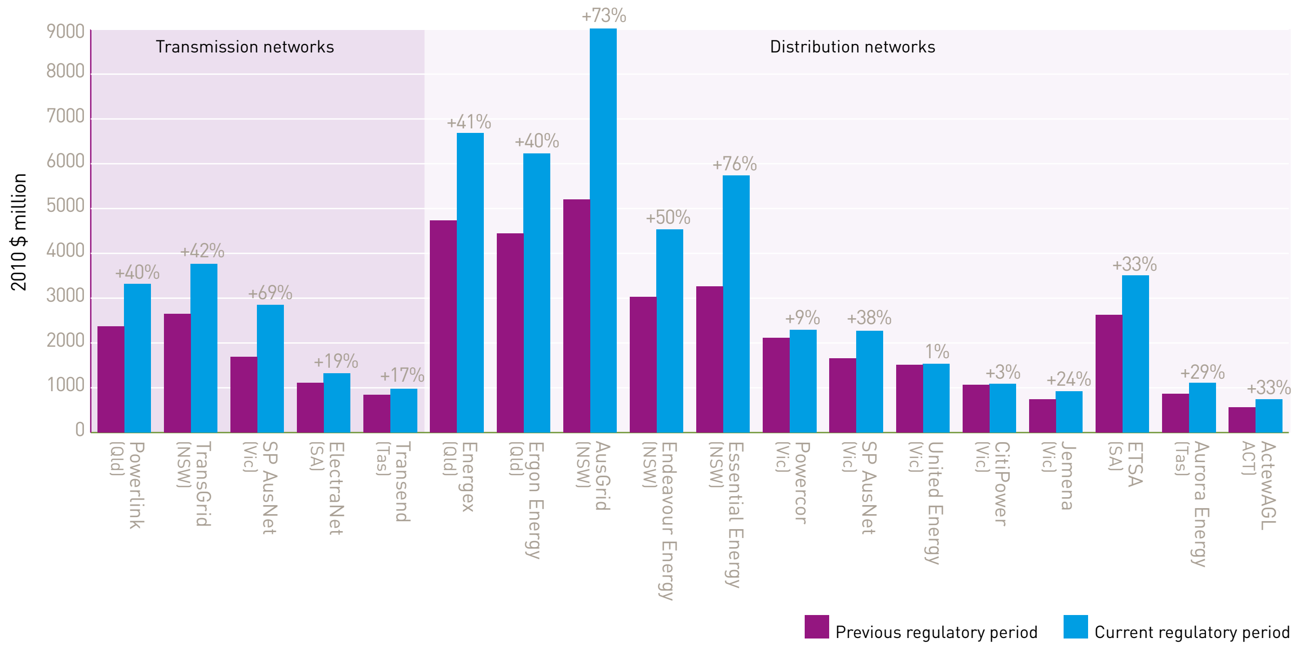
The regulatory process aims to create incentives for efficient investment. At the start of a regulatory period, the AER approves an investment (capital expenditure) forecast for each network. It can also approve contingent projects—large investment projects that are foreseen at the time of a determination,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

While the regulatory process approves a pool of funds for capital expenditure, each individual project must be assessed for whether it is the most efficient way of meeting an identified need, or whether an alternative (such as investment in generation capacity) would be more efficient.

There are separate assessment requirements 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.[5]

4 QCA, *Benchmark retail cost index for electricity: 2011–12, final decision*, 2011.
5 AER, *Regulatory test for network augmentation, version 3*, 2007.

Figure 2.3
Electricity network revenues



Notes:

Current regulatory period revenues are forecasts in regulatory determinations.

All data are converted to June 2010 dollars.

The current period revenue allowances for Energex and Ergon Energy are as determined by the Australian Competition Tribunal in May 2011. The Queensland Government prevented Energex and Ergon Energy from recovering $270 million and $220 million respectively of these allowances.

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

A new regulatory investment test for *transmission* (RIT-T) took effect on 1 August 2010.[6] Transmission projects are now assessed under a framework that is more comprehensive and applies to a wider range of investment projects than previously. It also gives more prescription of the market benefits and costs that the analysis can consider.

Two RIT-T processes began in the first year that the test was in place:

> TransGrid began consulting on a network upgrade around the Gunnedah, Narrabri and Moree areas of New South Wales.

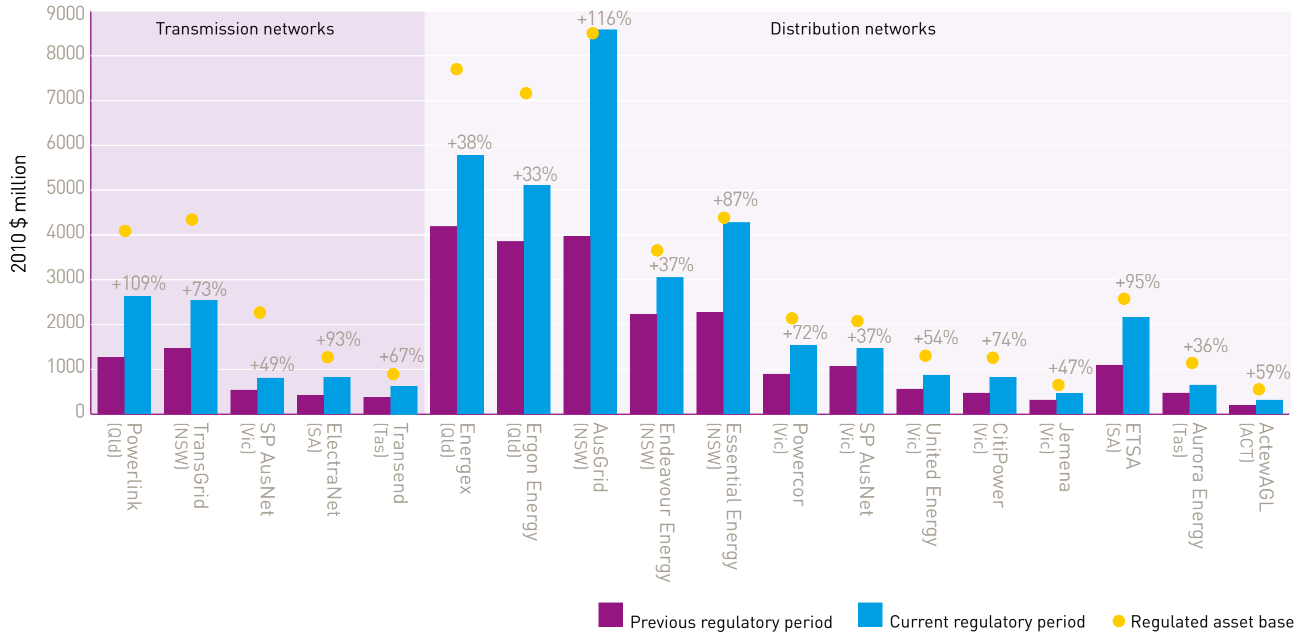
> SP AusNet (transmission) and CitiPower (distribution) initiated joint consultation on an upgrade to the Brunswick Terminal Station in Victoria.

In September 2011 the Australian Energy Market Commission (AEMC) began consulting on a Rule change to introduce a test similar to the RIT-T for distribution.[7] This RIT-D test will apply to projects over $5 million (but with scope for the AER to conduct audits on projects under $5 million to confirm non-network options were considered). The proposal includes a new dispute resolution process, and requirements on distribution businesses to release annual planning reports and maintain a demand side engagement strategy.

6 AER, *Regulatory investment test for transmission*, 2010.

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

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.

Investment data include capital contributions and do not include adjustments for disposals.

AusGrid's distribution network includes 962 kilometres of transmission assets.

All data are converted to June 2010 dollars.

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

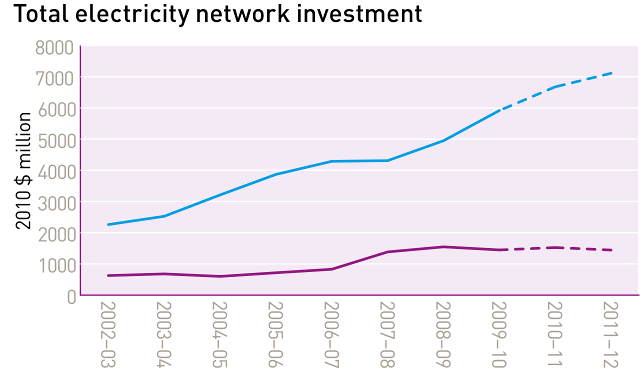
2.4.1 Investment trends

Figure 2.4 illustrates investment allowances for electricity networks in the current five year regulatory periods compared with previous 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 $35 billion for distribution networks. These forecasts represent an increase on investment in the previous regulatory periods of around 82 per cent in transmission and 62 per cent in distribution (in real terms).

On an annual basis, transmission investment in the NEM totalled around $1.4 billion in 2009–10 and was forecast to plateau around this level to 2011–12 (figure 2.5). Distribution investment was expected to rise from around $5 billion in 2009–10 to $6 billion in 2011–12.

Figure 2.5
Total electricity network investment



Notes:

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

Transmission investment excludes private interconnectors.

All data are converted to June 2010 dollars.

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

The factors driving higher levels of investment vary across networks and depend on a network's age and technology, load characteristics, the demand for new connections, and licensing, reliability and safety requirements. Differences in operating environments can result in significant variations in capital investment requirements (figure 2.4).

Recent AER determinations reflected that:

- the *Queensland* networks have capital requirements associated with population growth, new connections and industrial demand, as well as rising demand per customer. The distribution networks are also obliged to improve performance in response to stricter reliability standards.
- the *New South Wales* networks have ageing assets, requiring significant replacement and reinforcement capital expenditure. The networks have also experienced growth in peak demand.
- the *Victorian* distributors operate mostly mature and comparatively reliable networks. Capital expenditure is required to replace ageing infrastructure, address Victoria's new bushfire safety standards, and maintain reliability in the face of rising costs and demand.
- the *South Australian* networks require investment to meet rising load growth and peak demand driven by the use of air conditioners during summer heatwaves. The networks also need to address reliability risks from ageing assets and new reliability standards for the Adelaide central business district (involving upgrades to transmission and distribution systems).
- the *ACT* networks require increased capital investment, but not to the extent of other jurisdictions. As in New South Wales, the ACT distribution network requires the replacement of ageing network assets. The local network business, ActewAGL, faces a changing regulatory environment, with new legal obligations on safety, security, reliability and environmental issues.

Other factors affecting network investment include changes to system operation due to climate change policies and the introduction of smart meters and grids.

In contrast to the mainland jurisdictions, Tasmania's distribution network (Aurora Energy) proposed capital investment requirements for the regulatory period beginning 1 July 2012 that are below levels in the current period. While at October 2011 the AER had not completed its review of the proposal, Aurora Energy committed to avoiding unnecessary customer price increases, while ensuring a safe and reliable supply of electricity. To do so, it aims to drive cost reductions from current service delivery methods, together with the selective deployment of innovative technologies.

Aurora's proposal recognises that significant capital and operating expenditure in the current period has contributed to a strong and resilient network. This, coupled with subdued economic growth forecasts in Tasmania, would limit network expenditure requirements.[8]

2.5 Operating and maintenance expenditure

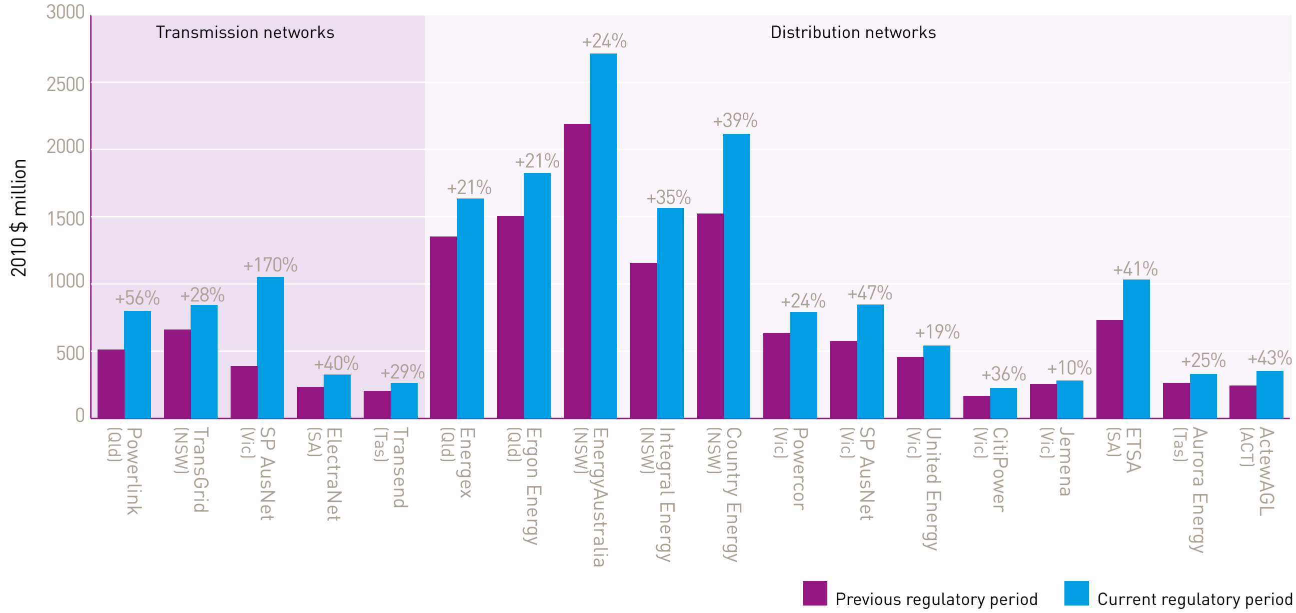
The AER determines allowances for each network to cover efficient operating and maintenance expenditure. The needs of a network depend on load densities, the scale and condition of the network, geographic factors and reliability requirements.

Figure 2.6 illustrates operating expenditure allowances for electricity networks in the current five year regulatory periods compared with previous periods. In the current cycle, transmission businesses will each spend, on average, around $130 million per year on operating and maintenance costs. In distribution, operating costs per business are forecast at around $220 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 64 per cent in transmission and 29 per cent in distribution over the current regulatory periods. Differences in the networks' operating environments (section 2.4.1) resulted in significant variations in expenditure allowances (figure 2.6).

8 Aurora Energy, *Energy to the people: Aurora Energy regulatory proposal 2012–2017*, 2011.

Figure 2.6
Operating expenditure of electricity networks



Notes:

Current regulatory period expenditure reflects forecasts in regulatory determinations.

The increase in SP AusNet's transmission operating expenditure in the current period was partly due to the introduction of an easement land tax mid way through the previous period (around $80 million per year).

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

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 2010 Victorian determinations, for example, accounted for an expected increase in regulatory compliance costs 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 a national incentive scheme for businesses to make efficient operating and maintenance expenditure in running their networks. The scheme allows 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.

The forecast level of expenditure determines the base level for calculation of efficiency gains or losses, after certain adjustments. Under the incentive scheme, a business retains around 30 per cent of efficiency gains or losses against the forecast, and passes on the remaining 70 per cent to customers through price adjustments.

The incentive scheme applies to all transmission and distribution networks, except the Tasmanian distribution network (Aurora)—to which it will apply from 1 July 2012. In June 2011 the AEMC began consulting on a proposal to amend the transmission scheme by excluding expenditure on non-network alternatives from the performance assessment, thus removing a disincentive to undertake this type of expenditure. The distribution scheme already excludes this expenditure.

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, animals, vehicle impacts or vandalism.

While a serious transmission network failure may require the power system operator to disconnect some customers (known as load shedding), over 90 per cent of power outages are caused by reliability issues in distribution networks.[9] 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

Transmission service issues relate principally to reliability and network congestion. This section considers reliability, while section 2.7 considers 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.

State and territory agencies determine transmission reliability standards. The AEMC in 2008 recommended to the Standing Council on Energy and Resources (SCER, formerly the Ministerial Council on Energy) that a national framework for transmission reliability standards be introduced to achieve a more consistent national approach. The framework would economically derive standards using a customer value of reliability or a similar measure. Standards would be determined on a jurisdictional basis by a body independent of transmission network owners. A national reference template would provide a basis for comparing the standards in each jurisdiction, and jurisdictions would need to justify any divergence from the template. The AEMC updated its recommendations in December 2010. At October 2011 the SCER was finalising its policy position on the review.

Energy Supply Association of Australia data indicate the NEM jurisdictions have generally achieved high rates of transmission reliability. In 2009–10 total unsupplied energy was higher than in the previous year in all jurisdictions except Victoria (which had unusually high levels of unsupplied energy in 2008–09). Unsupplied energy in Tasmania totalled 11 minutes. This followed a period of improved reliability, with less than 2 minutes of unsupplied energy in the previous year. Total unsupplied energy was around 3 minutes in South Australia, and 1 minute in New South Wales and Victoria.

The AER's national service target performance incentive scheme provides incentives for transmission businesses to maintain or improve 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).

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

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Table 2.3 S factor values

	2005	2006	2007	2008		2009		2010
Powerlink			0.82		0.53		0.20	0.65
TransGrid	0.70	0.63	−0.12		0.31	0.20	−0.30	−0.24
AusGrid	0.67	0.39	−0.14		0.72		0.37	
SP AusNet	0.09	−0.17	0.06	0.15	0.82		0.50	0.58
ElectraNet	0.71	0.59	0.28	0.29	−0.40		0.60	0.00
Transend	0.19	0.06	0.56		0.85	0.90	0.10	0.11
Directlink		−0.54	−0.62		−1.00		−1.00	−1.00
Murraylink		0.21	−0.32		0.69		0.90	1.00

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. AusGrid data for 2009 are for the six months to June; AusGrid moved to the distribution performance framework on 1 July 2009.

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

Source: AER, *Transmission network service providers: electricity performance report for 2009–2010*, 2011.

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 financial penalties in 2009 and 2010 were TransGrid and Directlink.

The AER commenced a review of the incentive scheme in October 2011. Any amendments will be applied to networks in their next regulatory period.

2.6.2 Distribution network reliability

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

State and territory agencies determine distribution reliability standards. The trade-off between reliability and cost means government decisions to increase reliability standards may require substantial new investment, with significant impacts on customer bills. The SCER in July 2011 noted the large contribution of distribution network investment to retail electricity prices, and directed the AEMC to review the frameworks for setting distribution reliability standards. This review follows an AEMC review of transmission reliability standards, completed in 2010 (section 2.6.1).

In November 2011 the AEMC released an issues paper on reliability outcomes in New South Wales. A broader review of the approaches used to determine reliability outcomes across the NEM will commence in 2012.

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

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	2009–10
SAIDI (MINUTES)										
Queensland	314	275	265	434	283	351	233	264	365	366
New South Wales	175	324	193	279	218	191	211	180	211	137
Victoria	152	151	161	132	165	165	197	228	255	170
South Australia	164	147	184	164	169	199	184	150	161	153
Tasmania	265	198	214	324	314	292	256	304	252	211
NEM weighted average	**198**	**245**	**199**	**258**	**211**	**221**	**211**	**213**	254	**200**
SAIFI (NUMBER OF INTERRUPTIONS)										
Queensland	3.0	2.8	2.7	3.4	2.7	3.1	2.1	2.4	2.9	2.7
New South Wales	2.5	2.6	1.4	1.6	1.6	1.8	1.9	1.7	1.8	1.5
Victoria	2.0	2.0	2.2	1.9	1.8	1.9	2.1	1.7	2.5	1.7
South Australia	1.7	1.6	1.8	1.7	1.7	1.9	1.8	1.5	1.5	1.9
Tasmania	2.8	2.3	2.4	3.1	3.1	2.9	2.6	2.6	1.9	1.8
NEM weighted average	**2.4**	**2.4**	**2.0**	**2.2**	**1.9**	**2.1**	**2.0**	**1.9**	2.2	**1.8**

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. Queensland data for 2009–10 are for the year ended 31 March 2010.

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

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* presents SAIDI data in graphical form (figure 2).

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. Geographic conditions and historical investment also differ across the networks.

Noting these caveats, the SAIDI data indicate electricity networks in the NEM 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.

In 2009–10 the average duration of outages per customer fell in all jurisdictions other than Queensland. Victoria and New South Wales experienced the greatest improvement, largely driven by benign weather. Reliability works programs and network capital expenditure may have contributed to the improved outcomes in New South Wales.

Queensland recorded a similar volume of outages in 2008–09 and 2009–10. Energex recorded a large fall in the average duration of outages on its network. But heavy rains, floods and Cyclone Ului contributed to increased outages on Ergon's network. 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.

The SAIFI data show the average frequency of outages has been relatively stable since 2002–03, with distribution customers across the NEM experiencing an outage around twice a year. The average frequency of outages fell in all jurisdictions in 2009–10, except South Australia. Victoria had the largest reduction in outage frequency, following decade high outage levels in 2008–09 associated with extreme weather (a heat wave and bushfires).

2.6.3 Customer service—distribution networks

The monitoring of service quality for distribution networks typically includes assessing customer service. Network businesses report on their responsiveness to customer concerns, 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. Service performance in 2009–10 broadly aligned with that of previous years. Timeliness of connections improved or was stable in all jurisdictions. Call centre performance also improved, with the percentage of phone calls answered within 30 seconds rising in all jurisdictions. New South Wales (particularly Essential Energy) delivered the most marked improvement.

2.6.4 Distribution service performance incentive schemes

Jurisdictions operate guaranteed service level (GSL) schemes that provide for payments to customers experiencing 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 require payments for poor service quality in matters such as streetlight repair, the frequency and duration of supply interruptions, new connections and notice of planned interruptions. Under the jurisdictional schemes, the majority of GSL payments in 2009–10 related to the duration and frequency of supply interruptions exceeding specified limits. In New South Wales, GSL payments fell in 2009–10 from the previous year due to improved performance in repairing streetlights; providing customers with better notice of planned interruptions (although the number of planned interruptions increased); and the timeliness of connections.

Aurora Energy (Tasmania) increased GSL payments in 2009–10 (to around $4.7 million, up from $0.9 million in 2008–09), largely due to outages caused by a major storm in September 2009. ETSA Utilities (South Australia) also increased GSL payments in 2009–10, to almost $1.6 million—more than double the amount paid in any of the previous three years. The bulk of these payments ($1.2 million) was for prolonged interruptions generally associated with severe weather events.

The AER 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. It 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.

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.[10] The results are standardised for each network to derive an s factor that reflects deviations from target performance levels. While the scheme aims to be nationally consistent, it has flexibility to deal with the differing circumstances and operating environments of each network.

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

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				
	2005–06	2006–07	2007–08	2008–09	2009–10	2005–06	2006–07	2007–08	2008–09	2009–10
QUEENSLAND[1]										
ENERGEX	0.62	0.55	10.79	2.54	0.44	89.4	79.1	96.3	89.7	90.0
Ergon Energy	0.84	0.49	0.72	0.30	0.38	85.1	87.0	86.2	87.2	87.0
NEW SOUTH WALES[2]										
EnergyAustralia	0.02	0.02	0.01	0.02	0.01	81.3	74.3	81.1	79.7	89.1
Integral Energy	0.02	0.02	0.01	0.02	0.01	89.0	70.9	96.2	92.0	96.6
Country Energy	0.02	0.02	0.01	0.02	0.01	47.2	…	61.4	51.4	73.2
ActewAGL	…	…	…	…	…	39.7	62.4	70.5	…	…
VICTORIA[3]										
Powercor	0.06	0.04	0.02	0.01	0.02	86.7	89.4	90.0	86.6	85.3
SP AusNet	2.40	2.66	1.74	2.58	1.74	92.3	91.2	92.3	91.6	92.6
United Energy	0.29	0.05	0.08	0.12	0	72.9	74.0	73.0	73.1	76.2
CitiPower	0.03	0.05	0.01	0	0.02	85.7	87.2	87.8	82.0	82.3
Jemena	0.09	0.19	0.80	0.89	0.11	77.4	79.9	73.1	77.4	77.2
SOUTH AUSTRALIA[1]										
ETSA Utilities	1.33	0.51	1.30	0.58	0.60	85.2	89.3	88.7	88.5	88.6
TASMANIA										
Aurora Energy	0.15	0.14	2.00	1.77	1.08	…	…	…	…	…

1. Completed connections data for Queensland and South Australia include new connections only. Queensland data for 2009–10 are for the period 1 July 2009 to 31 March 2010.
2. New South Wales completed connections data 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.

The national scheme applies to the Queensland, Victorian 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 in Tasmania from the start of Aurora Energy's next regulatory period (1 July 2012).

Victorian distribution businesses will be subject to an additional scheme from 1 January 2012 that provides incentives for the businesses to reduce the risk of fire starts in their networks. A fire start includes any fire that originates from a network, or is caused by something coming into contact with the network. This 'f factor' scheme will reward or penalise the businesses $25 000 per fire under or over their fire start targets.

2.7 Electricity transmission congestion

Physical limits (constraints) are imposed on electricity flows along transmission networks to avoid damage and maintain power system stability. These constraints can lead to network congestion, especially at times of high demand. Some congestion results from factors within the control of a service provider—for example, the scheduling of outages, maintenance and operating procedures, and 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.

Figure 2.7
Number of mispriced connection points

Source: AEMO.

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. 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

To provide information on patterns of congestion and expected market outcomes, AEMO developed a Congestion Information Resource. The resource includes data on 'mispricing', which occurs when network congestion causes a generator to be constrained on or off.[11] 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 three years. It illustrates 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.

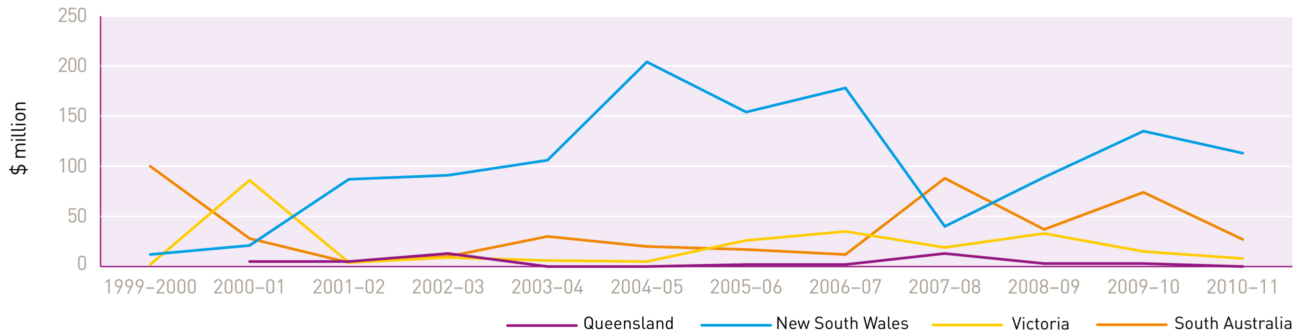
2.7.2 Reducing congestion costs

The AER in 2008 introduced an incentive scheme to reduce congestion. The mechanism forms part of the service performance incentive scheme.[12] It operates as a

11 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.

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

Figure 2.8
Settlement residues in the National Electricity Market



Source: AEMO.

bonus only scheme and rewards transmission network owners for improving their operating practices to reduce congestion. These practices may include more efficient outage timing and notification, the minimising of outage impact on network flows (for example, by conducting live line work, maximising line ratings and reconfiguring the network) and equipment monitoring. 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.[13]

TransGrid, Powerlink, ElectraNet and SP AusNet participate in the scheme. From early indications, the scheme is driving improved behaviour by the transmission businesses. TransGrid received $11.62 million in incentive payments between July 2009 and December 2010, and Powerlink received $6.83 million in incentive payments between July 2010 and December 2010. ElectraNet's performance target was set in December 2010, and SP AusNet's in August 2011. The first performance assessments for these businesses will occur in 2012.

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. The data show some volatility, because a complex range of factors can lead to price separation—for example, the availability of transmission interconnectors and generation plant, weather conditions and the bidding behaviour of generators.

As the NEM's largest electricity importer, New South Wales is vulnerable to price separation events and typically records the highest level of settlement residues. South Australian residues fluctuated over the past four years, reflecting movements in regional spot prices. As net exporters, Queensland and Victoria tend to accumulate modest settlement residues.

13 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.

2.8 Policy developments for electricity networks

The AEMC undertakes reviews on its own initiative or as directed by the SCER, and provides policy advice on electricity market issues. It is also responsible for Rule making under the Electricity Law, including determinations on proposed Rule changes. It progressed or finalised a number of reviews and Rule change proposals in 2011.

2.8.1 Total factor productivity

In July 2011 the AEMC published its final report on a total factor productivity approach to regulating network revenues and prices.[14] The approach would expose 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, including:

- a less information intensive approach, with reduced regulatory costs
- reduced information asymmetry between regulated businesses and regulators
- stronger performance incentives for regulated businesses, including incentives to undertake demand management.

It found a total factor productivity approach—especially in distribution—could lead to more efficient outcomes for consumers. It considered, however, that existing regulatory data may not be sufficiently robust or consistent to implement the approach in the short term.

In its final report, the AEMC proposed the SCER submit a Rule change proposal to facilitate the collection of more consistent and robust data from network businesses. Using the data, the AER could test whether the conditions necessary to introduce a total factor productivity approach have been met, which would allow paper trials to commence.

Interregional transmission charging

In February 2010 the SCER proposed a Rule change to implement new interregional charging arrangements for transmission networks. This change is designed to promote more efficient operation of, and investment in, the networks.

Under current arrangements, a transmission business recovers its costs from customers within the region in which its network is located. Customers in an importing region, therefore, do not pay the costs incurred in an exporting region to serve their load. The proposed Rule change would introduce a load export charge that effectively treats the business in the importing region as a customer of the business in the exporting region.

Consultation on the Rule change identified issues with existing transmission charging methods, including a lack of consistency in how charges are calculated across NEM regions. These issues could reduce the efficiency of the proposed scheme and make interregional charges more volatile. The AEMC is developing a uniform national interregional transmission charging regime to address these issues. It released a discussion paper in August 2011, setting out options.[15] A final Rule determination is expected by February 2012.

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 SCER proposed a Rule change to promote the efficient connection of clusters of new generation.

The AEMC finalised a Rule in June 2011 that aims to take advantage of economies of scale in network assets and avoid the inefficient duplication of connection assets.[16] The Rule requires a network business, at the request of a third party, to publish a study of

14 AEMC, *Review into the use of total factor productivity for the determination of prices and revenues, final report*, 2011.
15 AEMC, *National Electricity Amendment (Inter-regional Transmission Charging) Rule 2011*, Discussion paper, 2011.
16 AEMC, *National Electricity Amendment (Scale Efficient Network Extensions) Rule 2011, Rule determination*, 2011.

opportunities for efficiency gains from the coordinated connection of new generation in an area. This study would help investors make informed decisions about funding a network extension. Funding arrangements would be subject to commercial negotiation between the relevant entities. Once a network extension is constructed, other generators could seek access to it under a framework set out in the Rules.

Unlike the Rule as initially proposed, the adopted Rule does not compel anyone to bear the risk and cost of assets being underused. Rather, the risk is borne by investors with the appropriate information, ability and incentive to manage the risk.

Transmission frameworks review

The AEMC in 2011 continued its review of arrangements for the provision and use of electricity transmission services, and implications for the NEM's market frameworks. A consultative committee made up of energy market stakeholders was assisting the AEMC.

The review aims to ensure market frameworks—including incentives for generation and network investment—effectively align with frameworks for network operation to deliver efficient overall outcomes. It stems from earlier AEMC findings that climate change policies would affect the use of transmission networks and place stress on market frameworks.[17]

Based on issues raised in the review to date, the AEMC in April 2011 published a directions paper outlining matters for further holistic investigation, including:

- how generators access transmission services
- apportioning network charges between generators and users
- managing network congestion
- transmission planning, including the role of the RIT-T
- managing third party connections to the transmission network.

The final report is expected by June 2012.

2.9 Demand management and metering

Demand management relates to strategies to manage the growth in overall or peak demand for energy services. It aims to reduce or shift demand, or implement efficient alternatives to network augmentation. Such strategies are typically applied at the distribution or retail level, and require cooperation between energy suppliers and customers.

In distribution, the AER applies demand management schemes with incentives for businesses to investigate and implement efficient non-network approaches to manage demand. The schemes fund projects or initiatives that reduce network demand. In some jurisdictions, the schemes 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 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. A Rule change consultation on this issue commenced in June 2011.

2.9.1 Metering and smart grids

Meters record the energy consumption of customers at their point of connection to a 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) 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 2011.

17 AEMC, *Review of energy market frameworks in light of climate change policies, final report*, 2009.

The Victorian Government initiated a program outside the COAG process to provide smart meters to all customers over four years from 2009. Although the rollout is continuing, the government initiated a review of the program's future in 2011. The review includes a cost–benefit analysis to determine whether, and under what circumstances, the program can deliver consumers value for money. A moratorium exists on the introduction of time-of-use tariffs for customers with smart meters.[18]

Smart meter costs have been progressively passed on to Victorian retail customers since 1 January 2010. Network charges increased by almost $70 for a typical small retail customer in 2010, with a further increase of around $8 in 2011. In October 2011 the AER released a final determination on metering services budgets and charges for 2012–15.[19] Over this period, smart meter costs will increase network charges for a typical small retail customer by $9–21 per year.[20]

In addition to smart meter developments, the Australian Government in 2010 implemented a $100 million Smart Grid, Smart City initiative to support the installation of Australia's first commercial scale smart grid. Based in Newcastle, New South Wales, the initiative explores the use of advanced communication, sensing and metering equipment to provide customers with improved energy use information, automation and savings, and to improve network reliability. The initiative is also looking at options to connect additional renewable and distributed energy and hybrid vehicles to the grid.

18 If the customer consumes less than 20 megawatt hours of electricity per year.
19 AER, *Victorian advanced metering infrastructure review—2009–11 AMI budget and charges applications, final determination*, 2009.
20 AER, *Victorian advanced metering infrastructure review—2012–15 AMI budget and charges applications, final determination*, 2011.