TransGrid

2 ELECTRICITY NETWORKS

Electricity networks provide a means of transporting 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.

While energy networks traditionally provided a one-way delivery service to customers, recent technological innovations mean networks can provide a platform for trading a variety of electricity services.

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 (NSW), 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. It comprises 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, NSW and Victoria each have multiple networks that are monopoly providers in 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 735 000 kms—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 Queensland, NSW and Tasmanian networks are all government owned. The ACT distribution network has joint government and private ownership.

All transmission networks in Victoria and South Australia, and three interconnectors (Directlink, Murraylink and Basslink) are privately owned. Victoria's five distribution networks are also privately owned, while the South Australian distribution network is leased to private interests:

- *Cheung Kong Infrastructure* and *Power Assets* 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 (SA Power Networks, formerly ETSA Utilities). The remaining 49 per cent of the two Victorian networks is held by Spark Infrastructure, a publicly listed infrastructure fund in which Cheung Kong Infrastructure has a direct interest.
- *Singapore Power International* has a minority ownership in Jemena (which owns the Jemena distribution network in Victoria) and part owns the United Energy (Victoria) and ActewAGL (ACT) distribution networks. Singapore Power International also has a 51 per cent stake in AusNet Services, which owns Victoria's transmission network and the AusNet Services distribution network.
- *State Grid Corporation of China* entered the Australian market in 2012, purchasing a 41 per cent stake in the South Australian transmission network. It raised its stake to 46 per cent in 2013. In 2013 it acquired a 60 per cent stake in Jemena, and a 20 per cent share in AusNet Services from Singapore Power International. These businesses also own or have equity in the gas pipeline sector (chapter 4).

Victoria has a unique transmission network structure that separates asset ownership from planning and investment decision making. AusNet Services 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 AusNet Services for sale to customers.

In some jurisdictions, ownership links exist between electricity networks and other segments of the electricity sector:

- In the ACT, common ownership occurs in electricity distribution and retailing, with ring fencing arrangements for operational separation.[1]
- Queensland privatised much of its energy retail sector in 2006–07, but the state owned Ergon Energy continues to provide distribution and retail services.
- Tasmania had common ownership in electricity distribution and retailing until 1 July 2014, when the Tasmanian Government created a new business—TasNetworks—that merged the Transend transmission network and the Aurora Energy distribution network.

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 transmission grid and distribution networks in the National Electricity Market

QNI, Queensland–NSW Interconnector.

Table 2.1 Electricity transmission networks

NETWORK	LOCATION	LINE LENGTH (CIRCUIT KM)	ELECTRICITY TRANSMITTED (GWH), 2012–13	MAXIMUM DEMAND (MW), 2012–13[1]	ASSET BASE ($ MILLION)[2]	CURRENT REGULATORY PERIOD	OWNER
NEM REGION NETWORKS							
Powerlink	Qld	14 310	49 334	10 956	6 035	1 July 2012–30 June 2017	Queensland Government
TransGrid	NSW	12 893	65 200	17 100	5 289	1 July 2014–30 June 2015[3]	NSW Government
AusNet Services	Vic	6 573	49 056	9 342	2 414	1 Apr 2014–30 Mar 2017	Listed company (Singapore Power International 31%, State Grid Corporation 20%)
ElectraNet	SA	5 527	14 284	4 136	1 786	1 July 2013–30 June 2018	State Grid Corporation 46.5%, YTL Power Investments 33.5%, Hastings Utilities Trust 20%
TasNetworks	Tas	3 503	12 866	2 483	1 236	1 July 2014–30 June 2015[3]	Tasmanian Government
NEM TOTALS		42 806	190 740		16 760		
INTERCONNECTORS[4]							
Directlink	Qld–NSW	63				1 July 2005–30 June 2015	Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)
Murraylink	Vic–SA	180				1 July 2013–30 June 2018	Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)
Basslink	Vic–Tas	375				Unregulated	Publicly listed CitySpring Infrastructure Trust

GWh, gigawatt hours; MW, megawatts.

1 Transmission system non-coincident, summated maximum demand.

2 Asset bases are at June 2013 (December 2013 for Victorian businesses).

3 One year transitional arrangements are in place in NSW and Tasmania.

4 Not all interconnectors are listed. The unlisted interconnectors, which form part of state based networks, are Heywood (Victoria–South Australia), QNI (Queensland–NSW) and NSW–Victoria.

Sources: AER regulatory determinations and benchmarking regulatory information notices (RINs).

Table 2.2 Electricity distribution networks

NETWORK	CUSTOMER NUMBERS	LINE LENGTH (CIRCUIT KM)	ELECTRICITY DELIVERED (GWH), 2012–13	MAXIMUM DEMAND (MW), 2012–13[1]	ASSET BASE ($ MILLION)[2]	CURRENT REGULATORY PERIOD	OWNER
QUEENSLAND							
Energex	1 359 712	51 781	21 055	5 029	10 197	1 Jul 2010–30 Jun 2015	Qld Government
Ergon Energy	710 431	160 110	13 496	3 420	8 837	1 Jul 2010–30 Jun 2015	Qld Government
NEW SOUTH WALES AND ACT							
AusGrid	1 635 053	40 964	26 338	5 570	13 613	1 Jul 2014–30 Jun 2015[3]	NSW Government
Endeavour Energy	919 385	35 029	16 001	4 156	5 344	1 Jul 2014–30 Jun 2015[3]	NSW Government
Essential Energy	844 244	191 107	12 291	2 294	6 518	1 Jul 2014–30 Jun 2015[3]	NSW Government
ActewAGL	177 255	5 088	2 903	698	790	1 Jul 2014–30 Jun 2015[3]	ACTEW Corporation (ACT Government) 50%; Jemena (State Grid Corporation 60%, Singapore Power International 40%) 50%
VICTORIA							
Powercor	753 913	73 889	10 556	2 396	2 869	1 Jan 2011–31 Dec 2015	Cheung Kong Infrastructure / Power Assets 51%; Spark Infrastructure 49%
AusNet Services	681 299	43 822	7 501	1 877	2 809	1 Jan 2011–31 Dec 2015	Listed company (Singapore Power International 31%, State Grid Corporation 20%)
United Energy	656 516	12 837	7 856	2 077	1 789	1 Jan 2011–31 Dec 2015	DUET Group 66%; Jemena (State Grid Corporation 60%, Singapore Power International 40%) 34%
CitiPower	322 736	4 318	5 981	1 493	1 601	1 Jan 2011–31 Dec 2015	Cheung Kong Infrastructure / Power Assets 51%; Spark Infrastructure 49%
Jemena	318 830	6 135	4 254	986	1 031	1 Jan 2011–31 Dec 2015	Jemena (State Grid Corporation 60%, Singapore Power International 40%)
SOUTH AUSTRALIA							
SA Power Networks	847 766	87 883	11 008	2 915	3 469	1 Jul 2010–30 Jun 2015	Cheung Kong Infrastructure / Power Assets 51%; Spark Infrastructure 49%
TASMANIA							
TasNetworks	279 868	22 336	4 248	239	1 455	1 Jul 2012–30 Jun 2017	Tas Government
NEM TOTALS	9 507 007	735 298	143 488		60 322		

1 Non-coincident, summated, raw system, annual maximum demand at the zone substation level.

2 Asset bases are at June 2013 (December 2013 for Victorian businesses).

3 One year transitional arrangements are in place in NSW and the ACT.

Sources: AER regulatory determinations and benchmarking RINs.

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 a network when it was first regulated, plus subsequent new investment, less depreciation. The combined opening RAB of distribution networks in the NEM is around $54 billion—over three times the valuation for transmission infrastructure (around $17 billion).

2.2 Economic regulation of electricity networks

Energy networks are capital intensive and incur declining average costs as output increases. So, network services in a particular geographic area can be most efficiently provided by a single supplier, leading to a natural monopoly industry structure. In Australia, the networks are regulated to manage the risk of monopoly pricing and encourage efficient investment in infrastructure. The Australian Energy Regulator (AER) sets the prices for using 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 for 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 forecast expenditure and revenue requirements (typically, every five years). Chapters 6 and 6A of the National Electricity Rules set out the framework that the AER must apply in undertaking this role for distribution and transmission networks respectively.

The AER assesses a network business's forecasts of the revenue that the business requires to cover its efficient costs and an appropriate return. It uses a building block model that accounts for a network's operating and maintenance expenditure, capital expenditure, asset depreciation costs and taxation liabilities, and for a return on capital. Figure 2.2 illustrates the revenue components of the South Australian transmission network (for the regulatory period 2013–18) and Tasmanian distribution network (for 2012–17).

The largest component is the return on capital, which may account for up to two-thirds of revenue. 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) affect the return on capital. An allowance for operating expenditure typically accounts for a further 30 per cent of revenue requirements.

While the regulatory frameworks for transmission and distribution are similar, they do differ. In transmission, the AER determines a cap on the maximum revenue that a network can earn during a regulatory period. In distribution, the range of control mechanisms is wider, and the AER may set a ceiling on the revenue or prices that a distribution business can earn or charge during a period. The available control mechanisms for distribution include:

- weighted average price caps, allowing flexibility in individual tariffs within an overall ceiling—used for the NSW, Victorian and South Australian networks
- average or maximum revenue caps, setting a ceiling on revenue that may be recovered during a regulatory period—used for the Queensland, ACT and Tasmanian networks.

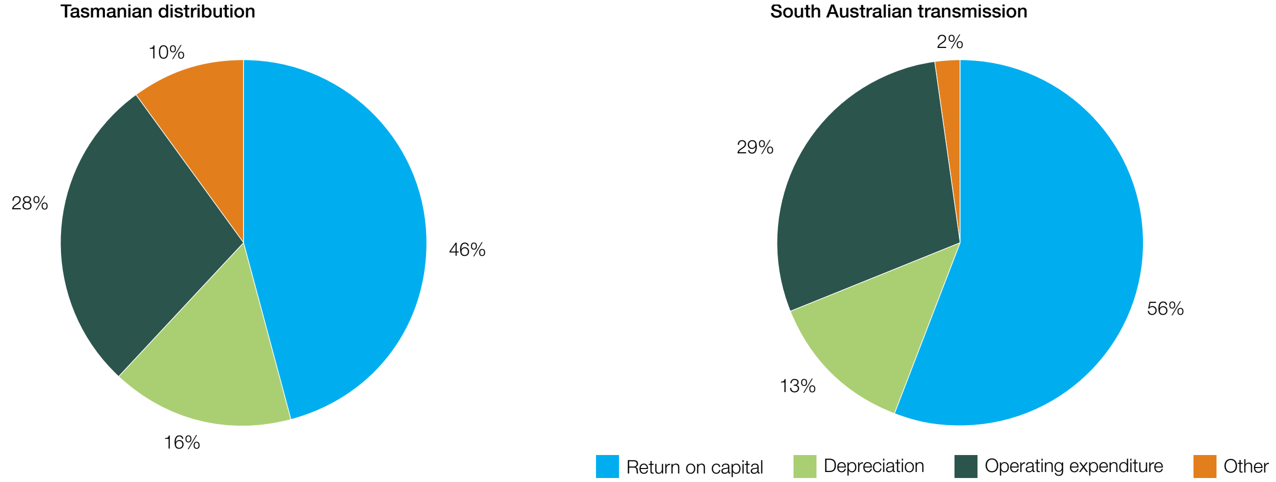
The regulatory process for network businesses begins with preliminary consultation on the framework and approach for the determination, around two years before the current regulatory period expires. The network business then submits a regulatory proposal to the AER, which assesses the proposal in consultation with stakeholders. The AER must publish a final decision on a proposal at least two months before the regulatory period starts.

2.2.2 Refining the regulatory process and approach

Energy consumers should pay no more than necessary for the safe and reliable delivery of electricity network services. Significant reforms to energy network regulation in the past few years encourage network businesses to seek more efficient ways of providing services. New measures support ongoing investment in essential services without requiring consumers to pay for excessive returns to network businesses.

The AER published guidelines in 2013 on how it will consider network proposals. The guidelines also cover new schemes to incentivise network businesses to invest and spend efficiently, and to share efficiency benefits with

Figure 2.2
Indicative composition of electricity network revenues



Source: AER.

consumers.[2] The approaches include a greater emphasis on benchmarking in assessing network proposals.

The reforms set out rules that first apply to regulatory determinations taking effect in 2015 for transmission networks in NSW and Tasmania, and for distribution networks in NSW, Queensland, South Australia and the ACT.

2.2.3 Regulatory timelines and recent AER activity

Figure 2.3 shows the regulatory timelines for electricity networks in each jurisdiction. In 2014 the AER:

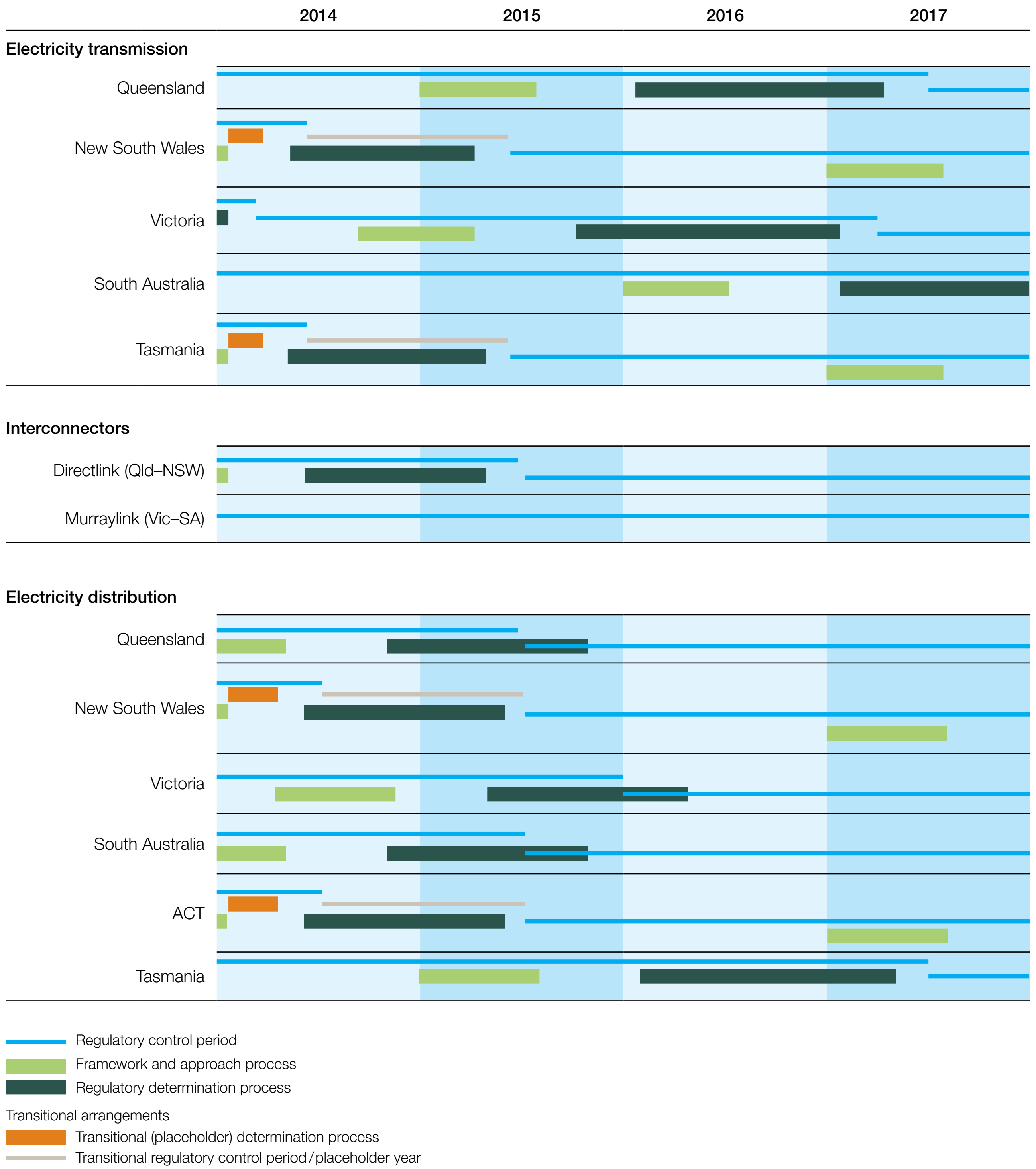
- made a final determination for AusNet Services (Victorian transmission) for the three year regulatory period commencing 1 April 2014. Work also commenced in late 2014 on the framework and approach for this network for the period commencing 1 April 2017.
- made transitional decisions under the new rules for transmission networks in NSW and Tasmania, and distribution networks in NSW and the ACT, to apply in 2014–15. In November 2014 the AER released draft decisions on new arrangements to replace the transitional arrangements from 1 July 2015.
- released a draft determination in November 2014 for Directlink (transmission interconnector between Queensland and NSW), covering the regulatory period commencing 1 July 2015
- began assessing proposals for the Queensland and South Australian distribution businesses, covering regulatory periods commencing 1 July 2015
- established a framework and approach to review the Victorian distribution businesses for regulatory periods commencing 1 January 2016.

In addition to revenue determinations, the AER undertakes other economic regulation functions. It assesses network proposals on matters including cost pass-throughs and contingent projects; develops and applies service incentive regimes, ring fencing policies and other regulatory guidelines; assists in access and connection disputes; and undertakes annual tariff compliance reviews of distribution businesses. The AER also monitors the compliance of network businesses with the Electricity Rules, and reports on outcomes, including in quarterly compliance reports.[3]

2 For a summary of the reforms, see AER, *State of the energy market 2013*, table 2.3, pp. 66–7.

3 AER, *Strategic priorities and work program 2013–14*, 2013.

Figure 2.3
Indicative timelines for AER determinations on electricity networks



Source: AER.

2.2.4 Merits review by the Australian Competition Tribunal

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

The review framework was amended in November 2013 to link it more closely to the national electricity and gas objectives. The Tribunal must consider the overall balance of a determination in making its decision, and can consider any matters linked with the grounds of the appeal. It can consult with relevant users and consumers during a review.

To have a decision amended on review, the network business must demonstrate the AER erred, and that addressing the grounds of appeal would lead to a materially preferable outcome in the long term interests of consumers. The AER will have erred if it:

- makes an error of fact that was material to its decision, or
- incorrectly exercises its discretion, having regard to all the circumstances, or
- makes an unreasonable decision, having regard to all the circumstances.

If the Tribunal finds the AER erred, it can substitute its own decision or remit the matter back to the AER for consideration. At November 2014 no businesses had applied for review of an AER decision under the new framework.

Under the previous merits review framework, network businesses sought review of 18 AER determinations on electricity networks—three reviews in transmission and 15 in distribution.[4] The Tribunal's decisions increased allowable electricity network revenues by around $3.2 billion, with substantial 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 eight networks, with a combined revenue impact of over $900 million.

4 Four of the distribution reviews related to charges for advancing metering infrastructure (smart meters) in Victoria. In addition, two determinations were subject to judicial review under the *Administrative Decisions (Judicial Review) Act 1977* (Cwlth).

The Tribunal in August 2013 affirmed the AER's decision to reject significant price increases for Victoria's AusNet Services distribution network, which were intended to recover unanticipated costs of advanced metering infrastructure. In September 2014 the Federal Court dismissed AusNet Services' judicial review application on this matter.

2.3 Electricity network revenue

Figure 2.4 illustrates the AER's revenue allowances for electricity networks in the current five year regulatory periods compared with previous regulatory periods. Combined network revenue was forecast at $12.5 billion per year in the current regulatory cycle, comprising over $2.7 billion for transmission and $9.8 billion for distribution. The main revenue drivers are capital financing (section 2.3.1), capital expenditure (section 2.4) and operating costs (section 2.5).

Rising network costs drove escalating revenues and charges for several years. Costs rose to replace ageing assets, meet stricter reliability and bushfire (safety) standards, and respond to forecasts made at the time of rising peak demand. Additionally, instability in global financial markets exerted upward pressure on the costs of funding investment.

These pressures have eased more recently, lowering revenue and investment requirements for energy networks. Energy demand has declined, and is expected to remain below historical peaks in most regions for at least the next 20 years.[5] This has coincided with reductions in capital financing costs (see below) and governments moving to provide electricity network businesses with greater flexibility in meeting reliability requirements (section 2.8.1).

These developments account for a recent flattening out of network revenues. In determinations made since 2012, forecast revenues are an average 2 per cent *lower* than for the previous regulatory period. By comparison, average revenues rose by 30 per cent in determinations made between 2009 and 2011.

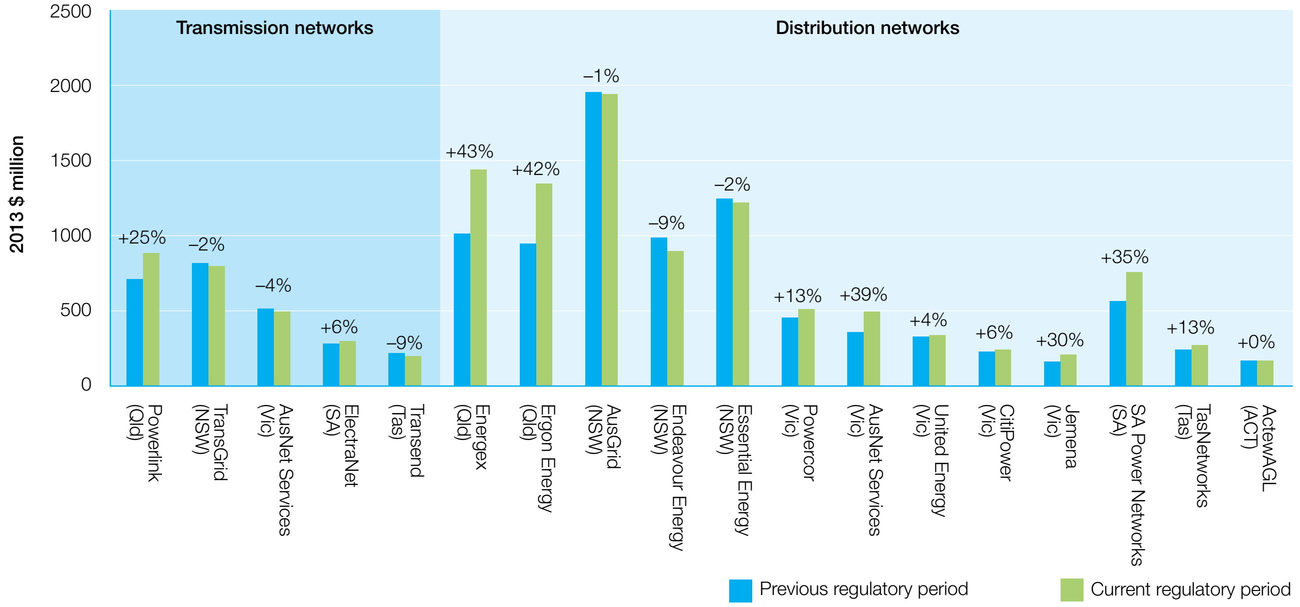
2.3.1 Capital financing

Electricity network businesses are capital intensive, so even small changes to the return earned on those assets can have a significant impact on overall revenue. As an example, a 1 per cent increase in the cost of capital allowed for ElectraNet in the AER determination for 1 July 2013 to 30 June 2018 would have increased revenues by 8 per cent.

5 AEMO, *Electricity statement of opportunities*, 2014.

Figure 2.4

Annual electricity network revenue



Notes:

Current regulatory period revenues are forecasts in regulatory determinations, amended for merits review decisions by the Australian Competition Tribunal.

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: AER regulatory determinations.

For AER determinations made from 2009 to 2011, the forecast cost of capital used to set revenue allowances was generally higher than in previous regulatory periods (figure 2.5). The primary factor underpinning the increases was a higher debt risk premium, which reflects the cost of borrowing for a business based on its risk of default. Issues in global financial markets reduced liquidity in debt markets and increased perceptions of risk from late 2008, pushing up the cost of borrowing.

AER determinations made since 2012 reflect that reductions in the risk-free rate and market and debt risk premiums have lowered the cost of capital. The overall cost of capital in electricity determinations made since 2012 was 7.5–8.3 per cent, compared with up to 10 per cent in 2010. The cost of capital set out in draft AER decisions in November 2014 was lower again, at 6.9–7.2 per cent. Under a revised framework that applied for the first time in these decisions, the cost of capital will be revised annually to reflect changes in debt costs.

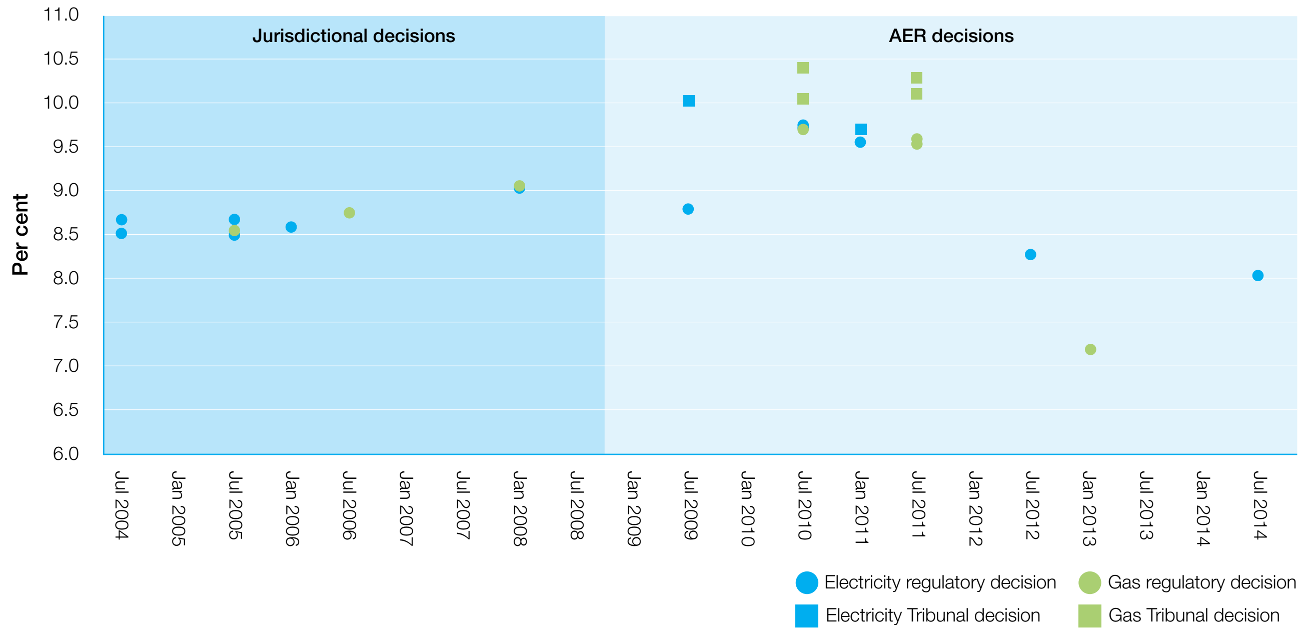
2.4 Electricity network investment

New investment in electricity networks includes augmentations (expansions) to meet 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 approve contingent projects too—large projects that are foreseen at the time of a determination, but that involve significant uncertainty.

While individual network businesses make investment decisions, AEMO (in its role as national transmission planner) provides high level planning and coordination of the transmission network. It publishes a national transmission network development plan that provides a long term strategic outlook.

Figure 2.5

Weighted average cost of capital—electricity and gas distribution



Note: Nominal vanilla weighted average cost of capital.

Source: AER.

2.4.1 Regulatory investment tests

The regulatory process approves the overall efficiency of a business's capital expenditure program. Additionally, separate consultation and assessment occur for large individual projects to determine whether they are the most efficient way of meeting an identified need, or whether an alternative (such as investment in generation capacity) would be more efficient. Under regulatory investment tests, network businesses must assess investment proposals against a market based cost–benefit analysis. A network business must identify the purpose of a proposed investment and assess that investment against all other credible options for achieving that purpose. The business must publicly consult on a proposal.

The current tests were introduced in August 2010 for transmission (RIT-T) and January 2014 for distribution (RIT-D). The AER:

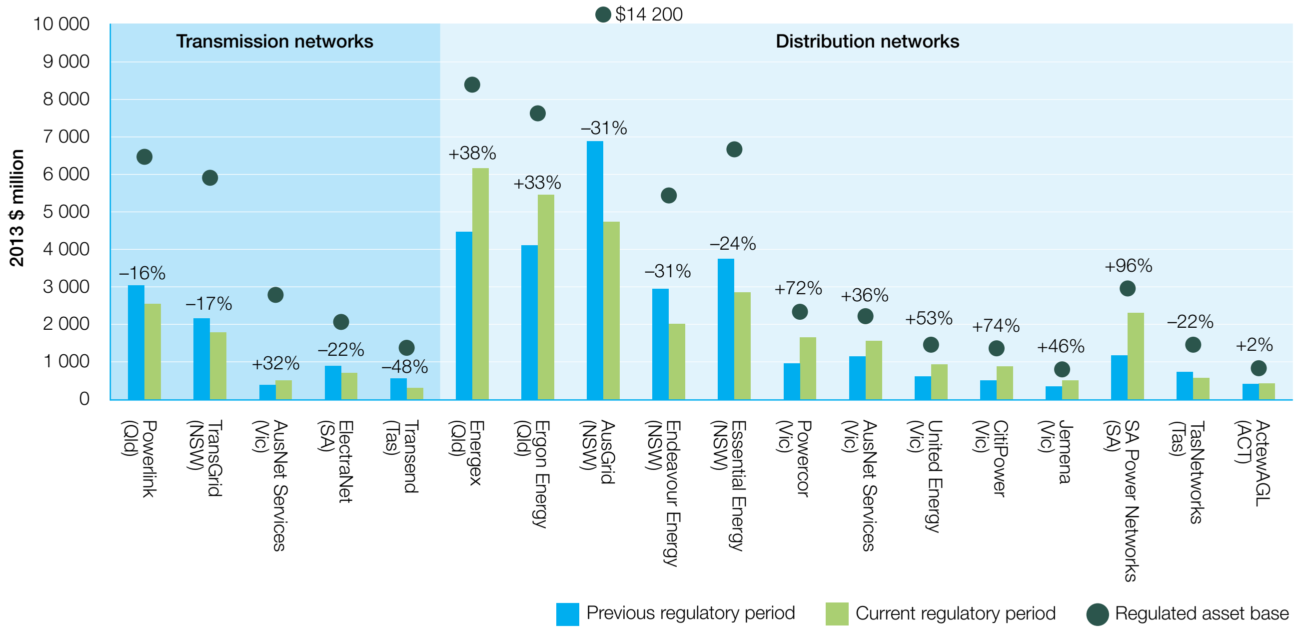
- publishes the tests and associated guidelines
- helps resolve disputes over how the tests are applied
- monitors and enforces compliance
- periodically reviews projects' cost thresholds
- determines whether a preferred investment option meets the RIT-T's cost–benefit analysis, on request from a business conducting the test. This role does not apply to reliability driven projects.

Forecasts of flat maximum demand growth in most regions over the next 10 years have reduced the number of planned network investment projects. Two RIT–D assessments were undertaken in 2014 in NSW and Victoria, along with four distribution projects assessed under the previous regulatory test. No new RIT–T assessments were commenced.

A number of previously initiated assessments progressed in 2014:

- TransGrid and Powerlink recommended no upgrade of the Queensland–NSW interconnector (QNI), citing uncertainty around the project's market benefits.
- Powerlink finalised an assessment of options to meet rising demand from new coal mine developments in the Bowen Basin. Consistent with its draft findings, it concluded a combined network and non-network option is the most efficient way to address emerging network limitations, with estimated net market benefits of up to $40 million.

Figure 2.6
Electricity network investment



Notes:

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

Investment data reflect forecast capital expenditure for the current regulatory period (typically, five years), amended for merits review decisions by the Australian Competition Tribunal. See tables 2.1 and 2.2 for the timing of current regulatory periods. The data include capital contributions and exclude adjustments for disposals.

Sources: AER regulatory determinations.

- AEMO released its preferred option for addressing thermal capacity limitations in regional Victoria. The project will consist of three stages, with the final stage on hold pending further assessment.
- AEMO deferred its assessment of projects to meet demand in eastern metropolitan Melbourne, following downward revisions to demand forecasts.
- Ergon Energy reassessed its planned $32 million transmission line from Warwick to Stanthorpe, finding changes in demand and network reliability requirements meant the project was no longer required.

2.4.2 Investment trends

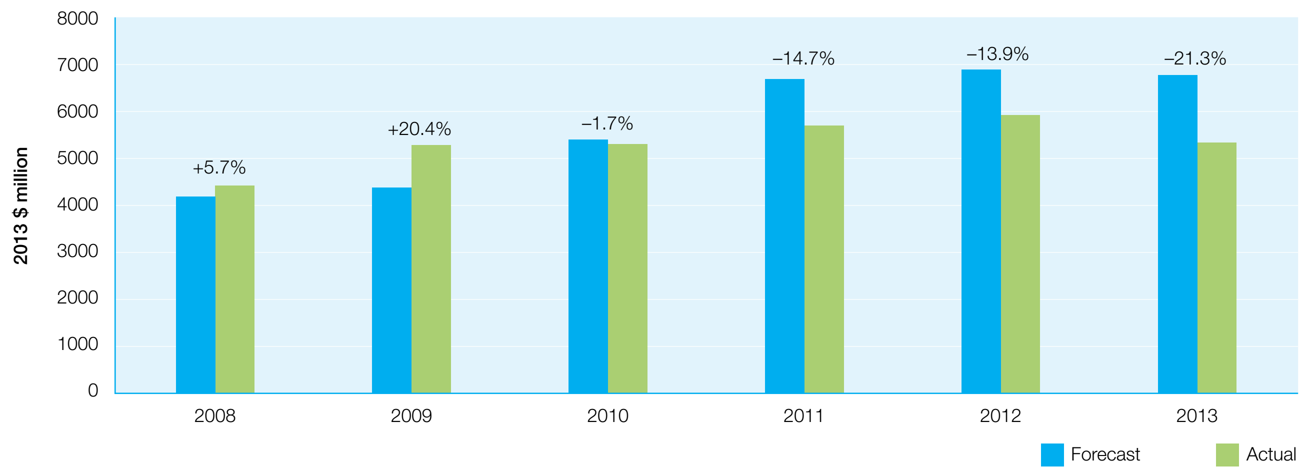
Figure 2.6 illustrates investment allowances for electricity networks in the current five year regulatory periods compared with previous regulatory periods. It shows the RAB for each network as a scale reference. Investment drivers vary across networks and depend on a network's age and technology, load characteristics, the demand for new connections, and licensing, reliability and safety requirements.

Network investment over the current regulatory cycle is forecast at $6 billion for transmission networks and $30 billion for distribution networks. AER determinations made from 2009 to 2011 reflected increased capital needs to replace ageing assets, meet higher reliability standards, and respond to forecasts made at the time of rising peak demand. The determinations provided for real investment to increase on average by 46 per cent, compared with the previous regulatory period.

Determinations made since 2012 reflect a different trend, with approved investment forecasts being 24 per cent *lower*, on average, than levels in previous periods. Weakening industrial and residential energy use, along with less stringent reliability obligations on the network businesses, are reducing the number of planned network investments and deferring projects that had already passed a regulatory investment test (section 2.4.1).

Investment trends for the AusGrid distribution network (NSW) illustrate that the effects of falling energy demand can be complex. The network's regulatory determination for 2009–14 provided for investment to meet an

Figure 2.7
Forecast and actual capital expenditure by distribution networks



Source: Annual financial RIN responses by distribution businesses.

expected increase in maximum demand from 5500 to 6700 megawatts over the period.[6] But these forecasts proved optimistic; maximum demand peaked at around 6000 megawatts. This outcome allowed the business to defer significant investment, leading it to underspend its allowance by $1.5 billion (around 20 per cent). While customers will benefit from the deferral of investment, they still bear costs during the current period, which are based on the higher expenditure forecasts. This trend of underspending occurred across all networks in recent years. Distribution businesses, for example, underspent their approved forecasts from 2011 to 2013 by an average 17 per cent (figure 2.7).

This trend of weakening investment forecasts is particularly reflected in a decline in network augmentation expenditure. Draft AER decisions for the NSW and ACT distribution networks in November 2014, for example, provided for $1.2 billion of augmentation expenditure (16 per cent of total capital expenditure), which is a quarter of the amount approved in the previous regulatory period ($5 billion, or 35 per cent of total capital expenditure).

New tools available to the AER through the Better Regulation program promote efficient capital expenditure. A capital efficiency benefit sharing scheme creates incentives for businesses to undertake efficient expenditure, by allowing them to retain a share of the gains (section 2.5.1). The AER will also review capital overspends; inefficient expenditure will be excluded from the business's asset base (meaning consumers will not pay for it).

6 AER, *NSW distribution determination 2009–10 to 2013–14, final decision*, 2009.

2.5 Operating and maintenance expenditure

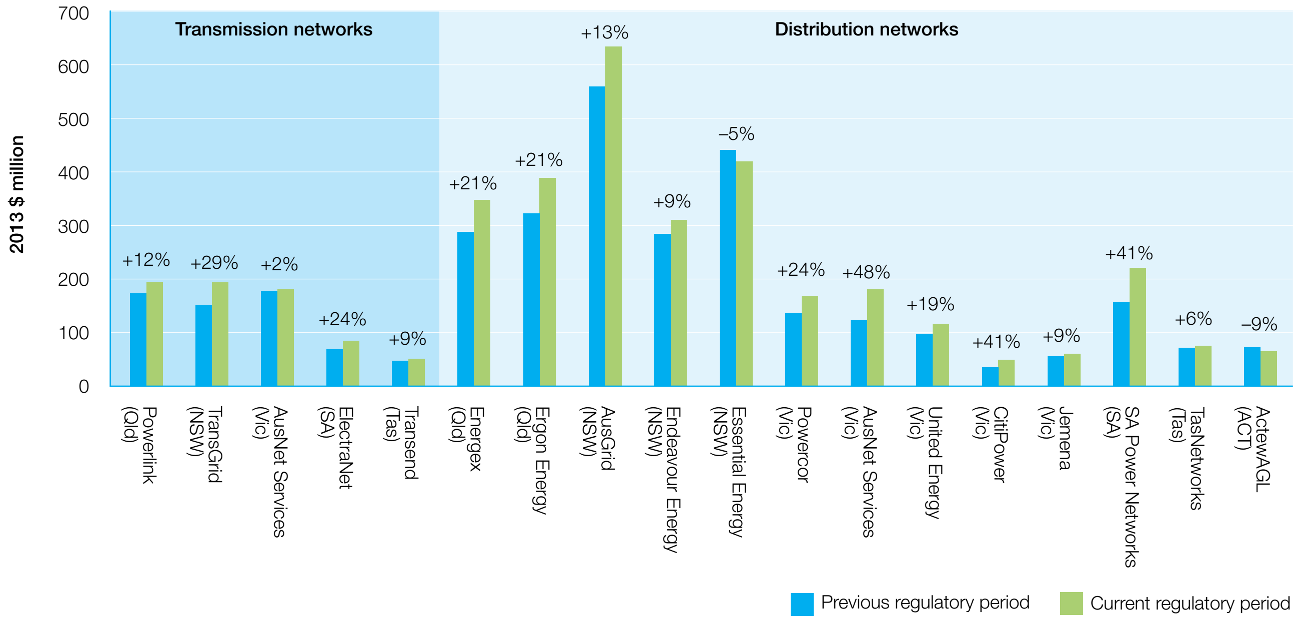
The AER determines allowances for each network to cover efficient operating and maintenance expenditure. A network's requirements depend on load densities, the scale and condition of the network, geographic factors and reliability requirements.

Figure 2.8 illustrates operating and maintenance expenditure allowances for electricity networks in the current five year regulatory periods compared with previous regulatory periods. In the current cycle, transmission businesses in the NEM are forecast to spend $720 million on operating and maintenance costs each year. Distribution businesses are forecast to spend $3 billion each year.

Differences in the networks' operating environments result in significant variations in expenditure allowances. On average, costs are forecast to rise by around 15 per cent across transmission and distribution networks in current regulatory periods compared with previous periods. Operating and maintenance costs are largely independent of energy use, so falling electricity demand does not significantly reduce this expenditure. From 2011 to 2013, total distribution network expenditure was within 1 per cent of AER approved forecasts.

In assessing operating expenditure forecasts, the AER considers relevant cost drivers, including customer growth, expected productivity improvements, and changes in real input costs for labour and materials. Operating cost increases may also reflect step change factors—that is, new

Figure 2.8
Annual operating expenditure of electricity networks



Note: Current regulatory period expenditure reflects forecasts in regulatory determinations, amended for merits review decisions by the Australian Competition Tribunal.

Sources: Regulatory determinations by the AER.

business requirements that were not part of the previous regulatory period. The 2013 ElectraNet (South Australian transmission) determination, for example, accounted for costs incurred under a new asset management policy that aims to detect faults before they become major problems. It also allowed for the costs of remediating high risk, low hanging transmission lines.

2.5.1 Efficiency benefit sharing scheme

The AER operates a national incentive scheme for businesses to improve the efficiency of operating and maintenance expenditure in running their networks. And, as part of the Better Regulation program, it is expanding the scheme to cover capital expenditure. Capital and operating expenditure incentives are aligned with those provided through the AER's service target performance incentive scheme, to encourage business decisions that balance cost and service quality.

The efficiency benefit sharing scheme, which applies to all transmission and distribution networks, 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.[7] In the longer term, the businesses share efficiency gains or losses with customers through price adjustments, passing on 70 per cent of the gain or loss. AER determinations for transmission networks since 2012 have provided penalties under the scheme for Powerlink ($4 million) and ElectraNet ($2 million), and a benefit under the scheme for AusNet Services ($37 million).

2.6 *Power of choice* reforms

The nature and function of energy networks is evolving. Escalating cost pressures have given impetus to alternatives such as demand response (where users adjust their energy use in response to price signals), small scale local generation (such as rooftop solar photovoltaic generation) and, potentially, energy storage technologies. Innovations in network and communications technology—including smart meters and interactive household devices—are allowing consumers to access real-time information on their energy use, and to better control how they manage that use.

These developments are transforming the nature of a network from being a one-way conduit for energy transportation, to a platform for multilateral trade in energy products. Some electricity consumers are becoming producers, able to switch from net consumption to net production in response to market signals. For example, over a million households have installed rooftop solar photovoltaic systems in the past few years. Further, customer investment in smart appliances and battery storage could shift the amount of power customers withdraw from or inject into a network throughout the day. These developments are slowing the growth in peak demand, reducing the need for costly network augmentations.

In 2012 the Australian Energy Market Commission (AEMC) launched *Power of choice*, an umbrella of reforms for the efficient use of energy networks and non-network alternatives. The Council of Australian Governments (CoAG) approved the adoption in principle of the reforms and proposed a series of rule changes to apply them. Progress has since occurred with network reforms (as outlined below), with other work streams relating to the wholesale market (box 1.3).

2.6.1 Metering

The *Power of choice* reforms recommended all new meters installed for residential and small businesses consumers be *smart meters* that can record energy consumption on a near real-time basis, and that have capabilities for remote reading and customer connection to the network. Smart meters provide consumers with better information about their energy use and greater control over how they manage it. They can also allow consumers to access a wider range of retail price offers, or take up competitive offers of demand management products.

Victoria was the first jurisdiction to progress these reforms, launching a rollout of smart meters with remote communications to all customers from 2009. The network costs of the rollout were progressively passed on to retail customers, with network charges rising by around $80 for a typical small customer from 2010–12, with further annual increases of $9–21 from 2012–15.[8] The rollout was close to completion in late 2014.

Regulated network businesses currently provide electricity meters on residential premises. But this arrangement can inhibit competition and consumer choice. It also discourages investment in metering technology that could support the uptake of new and innovative energy products and services.

The AEMC was consulting in 2014 on a CoAG Energy Council proposal to allow competition in the provision of metering and related services. It also progressed related reforms to allow customers more ready access to their electricity consumption data and for multiple trading relationships at the customer's connection point. The reforms aim to create a regulatory framework matching the realities of a dynamic and evolving energy market. The AEMC expects to publish a draft determination on the reforms in December 2014.

Linked to these reforms, the NSW Government in October 2014 announced a competitive framework for the voluntary rollout of smart meters. The framework aims to encourage competition by allowing metering providers, such as electricity retailers or other energy service providers, to offer smart meters to customers as part of energy deals.[9] In its current review of the NSW networks, the AER reclassified certain metering services, making them open to competition. It is also looking at other ways to facilitate the competitive framework. These ways include ensuring exit fees are not unreasonably high, so customers incur only the efficient costs of moving from legacy (regulated) meters to third party provided meters.

If network businesses offer services in a contestable market, then the costs should be clearly separated from the RAB. The AER sets ring fencing guidelines to ensure network businesses do not shift costs between regulated and unregulated activities. Ring fencing may also set out rules for non-discrimination or prohibit a network business engaging in a potentially contestable activity.

7 The AER's approved expenditure forecasts set the base for calculating efficiency gains or losses, after certain adjustments. To encourage wider use of demand management, the incentive scheme does not cover this type of expenditure.

8 AER, *Victorian advanced metering infrastructure review—2012–15 AMI budget and charges applications, final determination*, 2011.

9 Hon. Anthony Roberts MP, Minister for Resources and Energy, 'NSW gets smart about meters', Media release, Tuesday 28 October 2014.

2.6.2 Cost-reflective network prices

While smart meters allow consumers to monitor their energy use, price signals are needed to provide incentives for efficient demand response. Under traditional pricing structures, energy users pay the same network price regardless of how or when they use power. Charges to customers that consume large amounts of electricity at peak times do not reflect the costs imposed by those customers on the network. As an example, a residential consumer using a 5 kilowatt air conditioner at peak times causes around $1000 a year in additional network costs, but might pay only $300 under current price structures. Other customers cover the remaining $700, paying more than what it costs to supply their own network services.[10]

Similarly, customers with solar photovoltaic systems do not bear the full cost of their network usage under current price structures, which reward reductions in total energy consumption, regardless of whether this occurs at peak times. For example, a customer can save around $200 in network costs per year by installing a solar photovoltaic system and reducing their use of electricity from the grid. But because most solar energy is generated at non-peak times, the customer will reduce network costs by around $80 only, since they will still use the network at peak times. Other consumers without a solar photovoltaic system cross-subsidise the remaining $120 by paying higher network charges.[11]

To address these inefficiencies, *Power of choice* proposed network prices should vary depending on time of use, thus encouraging retailers to reflect those charges in customer contracts. Time varying prices encourage consumers to choose efficient times to use their electrical appliances (perhaps by shifting some use from peak times when charges are high, to off-peak times such as late evening). More generally, cost-reflective pricing structures may create incentives for customers to invest in local generation and smart devices.

To progress the matter, the CoAG Energy Council in 2013 proposed a rule change to reform distribution network pricing. The AEMC's November 2014 determination set out a new pricing objective and pricing principles for distribution businesses, so prices reflect the efficient costs of providing network services to each consumer. Network businesses will also need to consult with stakeholders when developing their charging structures, so those charges account for consumer impacts.

The reforms remove cross-subsidisation and provide for consumer responses that minimise network costs over time. Those responses include better timing of energy use and using technologies that help to manage efficient energy use and costs. The AEMC estimated 81 per cent of residential customers would face lower network charges in the medium term under cost-reflective pricing, and up to 69 per cent would have lower charges at peak times.[12] Business users with relatively flat load profiles could also expect lower network charges.

The AEMC's November 2014 determination requires the new charging structures to be implemented by 2017, giving energy customers time to adjust to the changes. Victoria was the first jurisdiction to implement time varying prices. From September 2013, Victorian small customers could choose to remain on a traditional tariff structure or move to a more flexible structure.

2.6.3 Demand management and embedded generation

The *Power of choice* reforms include a focus on demand management as an efficient response to rising peak demand. The AER runs incentive schemes for distribution businesses to investigate and implement non-network approaches to manage demand. The approaches include measures to reduce demand or provide alternative ways to meet supply (such as connecting small scale local generation). The incentive schemes fund innovative projects that go beyond initiatives funded through capital and operating expenditure forecasts. In some jurisdictions, the schemes allow businesses to recover revenue forgone as a result of successful demand reduction initiatives.

The CoAG Energy Council in 2013 proposed strengthening incentives for distribution businesses to undertake demand management projects that deliver a net benefit. It proposed:

- separating the current arrangement into two parts—an incentive scheme for demand management and an innovation allowance for demand management and the connection of embedded generation
- allowing the AER to compensate network businesses for lost profit arising from eligible demand management projects, and to offer incentives based on a proportion of the net market benefits of eligible projects.

10 Commissioner Neville Henderson (AEMC), Power of choice and other energy market reforms, Speech delivered to 2014 EUAA conference, 13 October 2014.

11 Paul Smith (CEO, AMEC), Responding to consumer demands, promoting competition and preparing for change, speech delivered to 2014 Australian Institute of Energy symposium, 22 September 2014.

12 Commissioner Neville Henderson (AEMC), Power of choice and other energy market reforms, speech delivered to 2014 EUAA conference, 13 October 2014.

Power of choice also focused on removing impediments to investment in embedded generation that connects directly to the distribution network. A range of stakeholders and market reviews suggested a lack of consistent technical standards for mid-scale embedded generator connections creates a barrier to deployments.

In April 2014 the AEMC finalised a rule change for a clearer enquiry and application process, and set out new information requirements. In May 2014, it commenced a further rule change process to give smaller embedded generator proponents greater flexibility and scope to negotiate a connection. Under the draft rule, released in August 2014, smaller generators can use the newly created connection process for larger embedded generators, or a more flexible negotiated process.

2.7 Transmission network performance

Measures of performance for electricity transmission networks include:

- the reliability of supply (the continuity of energy supply to customers) (section 2.7.1)
- the management of network congestion (section 2.7.2).

2.7.1 Transmission network reliability

Transmission networks are engineered and operated with sufficient capacity to act as a buffer against planned and unplanned interruptions in the power system. While a serious transmission network failure may require the power system operator to disconnect some customers (known as load shedding), most reliability issues originate in distribution networks (section 2.8.1).

Transmission networks in the NEM deliver high rates of reliability. According to Energy Supply Association of Australia data, transmission outages in 2012–13 caused less than two minutes of unsupplied energy across NSW and Victoria. However, Tasmania and South Australia experienced their highest levels of unsupplied energy in over 10 years, at 20.5 minutes and 10.7 minutes respectively. No data were published for Queensland.[13]

Transmission reliability standards

State and territory agencies determine transmission reliability standards. The CoAG Energy Council in February 2013 directed the AEMC to develop a national framework for expressing, setting and reporting on transmission reliability. The process was aligned with work previously commenced on a national framework for distribution network reliability (section 2.8.1).

The AEMC finalised work on the transmission framework in November 2013.[14] Jurisdictions would remain responsible for setting reliability standards (with the option of delegating to the AER), drawing on a transparent economic assessment and community consultation. The process would assess the capital and operating costs of different reliability outcomes and compare these costs with the value customers place on each level of reliability.

Reliability standards would be defined on an input basis, but with the potential for jurisdictions to supplement these standards with output measures. The AEMC recommended the standards be reviewed every five years (to align with the regulatory determination process), but with flexibility for adjustments to reflect new information.

The AEMC also recommended a national approach to reporting on reliability performance.

Value of customer reliability

During 2014, AEMO consulted with industry stakeholders on valuations of customers' willingness to pay for a reliable supply of electricity. The valuations are intended to assist electricity planners, asset owners and regulators to deliver secure and reliable electricity supplies while maintaining reasonable costs for customers. They will also form a key component of the proposed transmission reliability framework.

AEMO's September 2014 report found residential customer reliability values are similar across all NEM states.[15] Residential customers value avoiding outages that are lengthy or occur at times of peak demand. Overall though, business customers tend to value reliability more highly, than residential customers.

2.7.2 Transmission network congestion

Limits (constraints) are imposed on electricity flows along transmission networks to avoid damage and maintain power system stability. These constraints can result in network congestion, especially at times of high demand. Some congestion results from factors within the control of a network business—for example, the scheduling of outages,

13 ESAA, *Electricity gas Australia 2014*.

14 AEMC, *Review of the national framework for distribution reliability, final report*, September 2013; AEMC, *Review of the national framework for transmission reliability, final report*, November 2013.

15 AEMO, *Value of customer reliability review, final report*, September 2014.

maintenance and operating procedures, and network capability limits (such as thermal, voltage and stability limits). Factors such as hot weather can cause congestion by sharply raising air conditioning loads. Typically, congestion with high market impacts occurs on just a few days each year, and is often associated with network outages.

A major transmission outage combined with other generation or demand events can interrupt the supply of energy. But this scenario is rare in the NEM. Rather, the main impact of congestion is a change in the cost of producing electricity. In particular, transmission congestion increases the total price of electricity by displacing low price generation with more expensive generation. Congestion can also lead to inefficient electricity trade flows between the regions (section 1.8).

Not all congestion is inefficient. Reducing congestion through investment to augment the transmission network is an expensive solution. Eliminating congestion is efficient only to the extent that the market benefits outweigh the costs. The AER in 2008 introduced incentives encouraging network businesses to reduce the impact of outages on the wholesale market.

The AEMC's transmission frameworks review (completed April 2013) looked at options to manage network congestion. Its preferred approach is an 'optional firm access' regime, whereby generators pay for priority access to the network (section 2.7.4).

2.7.3 Service target performance incentive scheme—transmission

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

The scheme in place has three components:

- A *service component* sets performance targets for the frequency of supply interruptions, the duration of outages, and the number of unplanned faults on the network. It also covers protection and control equipment failures. The over- or underperformance of a network against its targets results in a gain (or loss) of up to 1 per cent of the network's regulated revenue.
- A *market impact component* encourages a network to improve its operating practices to reduce congestion. These practices may include more efficiently planning outage timing and duration, and minimising the outage impact on network flows (for example, by conducting live line work, maximising line ratings and reconfiguring the network). A business can earn up to 2 per cent of its regulated revenue if it eliminates all relevant outage events with a market impact of over $10 per megawatt hour.
- A *network capability component* offers incentive of up to 1.5 per cent of regulated revenue. Payments are available to fund one-off projects that improve a network's capability, availability or reliability at times when users most value reliability, or when wholesale electricity prices are likely to be affected. An eligible project may not exceed $5 million, and the total cost of funding through the component may not exceed 1 per cent of network revenue. AEMO helps prioritise projects that deliver best value for money to consumers, and the AER approves a project list. Network businesses face a penalty of up to 2 per cent of revenue in the final year of their regulatory period if they fail to achieve improvement targets.

The market impact component has been progressively applied to network businesses since 2009. The network capability incentive will apply first to transmission networks in NSW, Victoria and Tasmania from 2014.

Rather than impose a common benchmark target, the AER sets separate targets reflecting the circumstances of each network based on its past performance. The results under each component are standardised for each network, to derive an 's factor' that can range between –1 (the maximum penalty) and +4.5 (the maximum bonus).

Table 2.3 sets out s factors for each network for the past five years. While performance against individual component targets varied, the networks generally received financial bonuses for overall performance. Underperformance was most common in relation to transmission circuit availability targets.

TransGrid in 2013 recorded its worst performance under the service component since the scheme commenced, failing to meet its network availability and average outage duration targets. But improved outcomes under the market impact component meant the business's overall s factor was consistent with the previous year's. Directlink also received a financial penalty in 2013 under the service component of the scheme.

Most transmission networks applied the congestion component of the scheme in 2013, including Murraylink for the first time. Network performance in this area improved in 2013 in all regions other than Queensland. Total payments under the congestion component in 2013 were $33 million.

Table 2.3 S factor values

		2009		2010	2011	2012		2013	
Powerlink (Qld)	Service component	0.17		0.65	0.42	0.44	0.45	0.54	
	Market impact component			1.97	1.95	1.98	2.00	1.86	
TransGrid (NSW)	Service component	0.22	−0.28	−0.24	−0.13	−0.49		−0.61	
	Market impact component	0.39		1.45	1.39	1.48		1.58	
AusNet Services (Vic)	Service component	0.51		0.58	0.72	0.82		0.67	
	Market impact component				0.00	0.80		1.31	
ElectraNet (SA)	Service component	0.60		0.00	0.32	−0.30		−0.17	0.31
	Market impact component				0.52	0.00		1.90	0.00
Transend (Tas)	Service component	0.88	0.11	0.35	−0.41	0.33		0.57	
Directlink (Qld–NSW)	Service component	−0.98		−1.00	−0.87	−1.00		−0.47	
Murraylink (Vic–SA)	Service component	0.87		1.00	0.70	0.92		−0.41	0.59
	Market impact component								1.19

Notes: TransGrid and Transend reported separately for the first and second halves of 2009. Powerlink reported separately for the first and second halves of 2012. ElectraNet and Murraylink reported separately for the first and second halves of 2013.

Source: AER, *Service standards compliance report* for various businesses.

2.7.4 Optional firm access

The AEMC in April 2013 completed a review of how electricity transmission services are provided and used. From the review, it recommended progressing the design of an 'optional firm access' model to manage the risk of network congestion constraining the dispatch of generation plant. In March 2014 the CoAG Energy Council directed the AEMC to design and test the optional firm access model. During the year, the AEMC undertook development work on core elements of the model's design, and consulted widely with stakeholders.

An element of network performance that has attracted recent policy focus is that pockets of network congestion periodically interfere with the efficient dispatch of generation plant. On the direction of the CoAG Energy Council, the AEMC in April 2013 began work on an *optional firm access* model to better manage this issue. During 2014, it developed core elements of the model's design, and consulted widely with stakeholders.

Under the model, generators would pay transmission businesses to secure firm network access. Transmission businesses would plan and operate their networks to provide the agreed capacity, with charges to generators reflecting the cost of providing that capacity. If congestion prevented a generator with firm access from being dispatched, then non-firm generators contributing to the congestion would compensate firm generators for any loss.

The model also allows generators and retailers to buy firm interregional access, entitling them to the price difference between the relevant regions. Payments for interregional access would guide and fund the expansion of interconnectors.

Optional firm access is intended to create locational signals that account for congestion costs against network expansion costs, providing efficient locational signals for new and existing generation plant. As a result, generation and transmission investment would likely become more efficient. The model also provides incentives for transmission businesses to maximise network availability when it is most valuable to the market.

The AEMC also proposed changing the connections framework to strengthen competition and transparency in the market for constructing network assets required for generator connection. Construction, ownership and operation of connection assets that do not form part of the shared network would be contestable; construction of shared network assets used to connect a generator would also be contestable, but the network business would retain responsibility for their operation. Transmission network businesses would have to provide cost information to connection applicants, and publish standard contracts and design standards.

2.8 Distribution network performance

Measures of performance for electricity distribution networks include reliability of supply and levels of customer service.

2.8.1 Reliability of distribution networks

Reliability is a key service measure for a distribution network. Both planned and unplanned factors 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.

Most electricity outages in the NEM originate in distribution networks. The capital intensive nature of distribution networks makes it expensive to build sufficient capacity to avoid all outages. 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. For these reasons, distributors should try to keep outages to efficient levels—based on the value of reliability to the community, and the willingness of customers to pay for reliability—rather than trying to eliminate every possible interruption.

Capital investment to ensure the networks delivered on reliability requirements was a significant driver of rising network charges in recent years. The AEMC in September 2013 proposed a new approach to setting distribution reliability targets that weighs the cost of new investment against the value customers place on reliability and the likelihood of interruptions (section 2.7.1). The valuations customers place on reliability will feed into future regulatory determinations to ensure network investment delivers a secure and reliable electricity supply, while maintaining reasonable costs for consumers.

Some jurisdictions are already moving to reform distribution reliability standards. The removal of strict input based reliability standards for Queensland networks from 1 July 2014 is expected to save $2 billion in capital expenditure over the next 15 years. Supply interruptions will likely increase by 13 minutes for urban customers in 2020 (to 83 minutes compared with 69 minutes under the previous standard).[16]

Similarly, the NSW Government in July 2014 removed deterministic planning obligations placed on distributors in network licence conditions. The remaining conditions focus solely on 'output' standards for reliability, providing more discretion for the businesses to determine the most appropriate ways to plan their network to meet the standard.[17]

Concerns about the impact of network investment on retail electricity prices led the CoAG Energy Council in 2012 to call for a national framework on distribution reliability standards. In response, the AEMC in September 2013 proposed a new approach to setting distribution reliability targets. The approach, undertaken independently of the network provider, would weigh the cost of new investment against the value that customers place on reliability and the likelihood of interruptions, to help set efficient output based reliability targets. The assessment would account for specific areas of the distribution network with high economic or social importance. The AER's service target performance incentive scheme would provide incentives for network businesses to meet their reliability targets.

To progress this reform, the CoAG Energy Council in December 2013 requested the AEMC develop common definitions for distribution reliability measures as an interim measure. In September 2014 the AEMC published harmonised definitions of those measures. It proposed the AER develop guidelines to apply the definitions.

The CoAG Energy Council also conferred responsibility on the AER to establish values of reliability to customers, for setting reliability requirements in the round of regulatory determinations commencing in mid-2019. AEMO in 2014 finalised a review of the value of customer reliability that could be used for this purpose (section 2.7.1).

Distribution reliability indicators

The key indicators of distribution reliability in Australia are the system average interruption duration index (SAIDI) and the system 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.

16 Queensland Department of Energy and Water Supply, *Changes to electricity network reliability standards factsheet*.

17 AER, *Ausgrid distribution determination 2015–16 to 2018–19, draft decision, Attachment 6: Capital expenditure*, November 2014.

Figure 2.9 estimates historical data on the average duration (SAIDI) and frequency (SAIFI) of outages experienced by distribution customers. The data include outages that originated in the generation and transmission sectors. Issues with reliability data limit the validity of comparisons 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 experienced around 200–250 minutes of outages per year, but with significant regional variations.

The average outage duration across the NEM in 2011–12 was the lowest in a decade, partly because weather conditions were benign. But the average outage duration rose in all jurisdictions in 2012–13. The largest rise occurred for Queensland (590 minutes, up from 210 minutes in 2011–12) and Tasmania (450 minutes, up from 230 minutes).

Queensland experiences significant variations in performance, partly because its large and widely dispersed rural networks make it more vulnerable to outages than are other jurisdictions. It faced an increase in severe weather activity in 2012–13, including ex-tropical cyclone Oswald that disrupted network services over multiple days in January. Tasmanian performance was also affected by weather conditions, with bushfires on the Tasman Peninsula in January 2013 resulting in a large number of supply interruptions.

The SAIFI data show the average frequency of outages was relatively stable between 2003–04 and 2012–13, with energy customers across the NEM experiencing an outage around twice a year. The average frequency of outages in 2012–13 was higher than that of the previous year in all jurisdictions except NSW and Tasmania. However, the average frequency of outages across the NEM jurisdictions remained lower than the average over the past 10 years. Victoria recorded the largest increase in outage frequency, with 2.1 outages per customer (up from 1.7 outages in 2011–12).

Service target performance incentive scheme—distribution

Through its service target performance incentive scheme (section 2.8.3), the AER sets targets for the average duration and frequency of outages for each distribution business. The targets are based on outcomes for the business over the previous five years. From a customer perspective, the unadjusted reliability data in figure 2.9 are relevant. But, in assessing network performance, the AER normalises data to exclude interruption sources beyond the network's reasonable control.

In 2012–13 businesses other than Energex failed to meet at least one reliability target, with outage duration being the most common missed target. United Energy underperformed against all its reliability targets. AusNet Services missed all its targets relating to the frequency of momentary outages. The scheme did not apply to NSW and ACT network businesses.

2.8.2 Distribution service performance incentives

The AER's service target performance incentive scheme encourages distribution businesses to maintain or improve network performance. It focuses on supply reliability and customer service, including the timely connection of services and call centre performance. A guaranteed service level (GSL) component provides for a business to pay customers if its performance falls below threshold levels.[18]

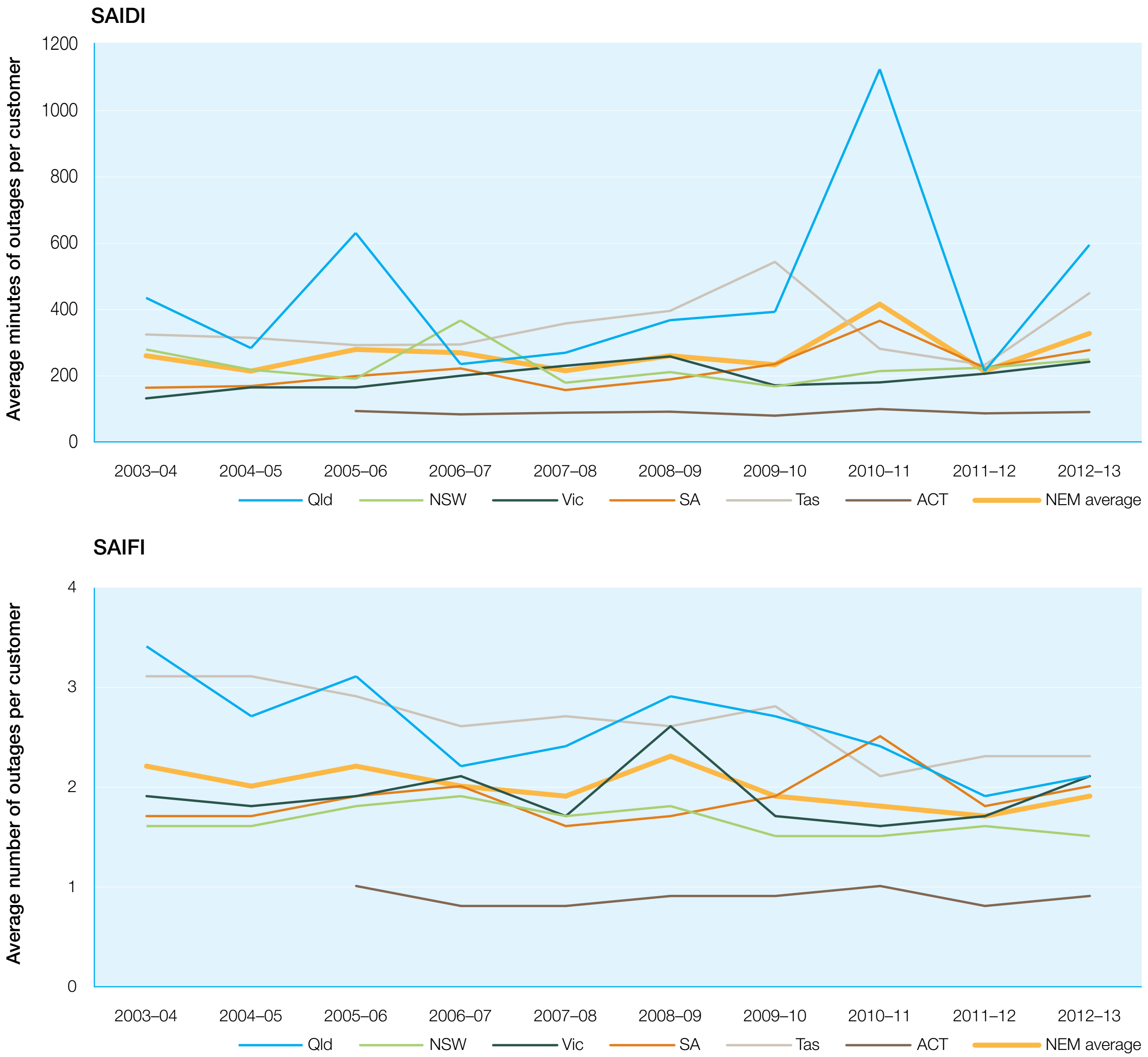
The incentive scheme provides financial bonuses and penalties of up to 5 per cent of revenue to network businesses that meet (or fail to meet) performance targets.[19] The results are standardised for each network, to derive an 's factor' that reflects deviations from target performance levels. While the scheme aims to be nationally consistent, it has flexibility to deal with the differing circumstances and operating environments of each network. The scheme applies in Queensland, Victoria, South Australia and Tasmania, and as a paper trial in NSW and the ACT (where targets are set but no financial penalties or rewards apply).

Since 1 January 2012, the Victorian distribution businesses have been subject to an additional scheme with incentives to reduce the risk of fire starts that originate from a network, or are caused by something coming into contact with the network. This 'f factor' scheme rewards or penalises the businesses $25 000 per fire under or over their targets. AusNet Services was the only business to outperform its target for 2013, receiving an incentive payment of $2 million. Penalties for the other businesses ranged from $65 000 for CitiPower to $2.4 million for Powercor.

18 The GSL component does not apply if the distribution business is subject to jurisdictional GSL obligations.

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

Figure 2.9
System reliability



Notes:

The data reflect total outages experienced by distribution customers, including outages originating in generation and transmission. The data are not normalised to exclude outages beyond the network operator's reasonable control.

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, the QCA (Queensland), the ESC (Victoria), ESCOSA (South Australia), OTTER (Tasmania), the ICRC (ACT), AusGrid, Endeavour Energy and Essential Energy. Some data are AER estimates derived from official jurisdictional sources.

Jurisdictional GSL schemes

Jurisdictional GSL schemes provide for payments to customers experiencing poor service. They mandate 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. The majority of payments in 2012–13 and 2013–14 related to the duration and frequency of supply interruptions exceeding specified limits. The outcomes are consistent with previous years' results:

- In Victoria in 2013, GSL payments rose in the United Energy, Powercor and CitiPower networks. However, overall payments fell to $6.2 million (from $7.5 million in the previous year) following a large reduction in reliability payments in the AusNet Services network (from $6.6 million in 2012 to $4.9 million in 2013).
- GSL payments rose by 57 per cent in Queensland's Energex network in 2012–13 (to $450 000), largely due to weaker reliability performance. Ergon Energy also had a large increase in payments for failing to meet outage duration targets, but these payments were offset by improved performance in notifying customers of supply interruptions. Both networks improved their performance against reliability targets in 2013–14, resulting in a 30–40 per cent fall in GSL payments.
- SA Power Networks (South Australia) and Aurora Energy (Tasmania) increased their GSL payments over the two years, following a rise in the number of severe weather events. SA Power Networks payments rose from $2.6 million in 2011–12, to almost $9 million in 2013–14. Aurora Energy's payments rose from $790 000 to $3 million.
- NSW networks do not have customer service payments related to reliability of supply. Payments in 2012–13 on other customer service measures—including timely provision of services and notice of interruptions—were at similar levels to those in the previous year.