SP AusNet

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. 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, 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 760 000 kilometres—17 times longer than transmission infrastructure. Figure 2.1 illustrates the transmission and distribution networks in the NEM.

2.1.1 Ownership

Tables 2.1 and 2.2 list ownership arrangements for electricity networks in the NEM. The Queensland, New South Wales 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 SP AusNet, which owns Victoria's transmission network and the SP AusNet distribution network. Singapore Power International contracted to sell a 60 per cent stake in Jemena, and a 20 per cent share in SP AusNet, to State Grid Corporation of China in 2013. The transaction was before the Foreign Investment Review Board in November 2013.
- *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 contracted to acquire stakes in electricity distribution assets 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. 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 the ACT,[1] common ownership occurs in electricity distribution and retailing, with ring fencing arrangements for operational separation.
- Tasmania also has common ownership in electricity distribution and retailing, with an attempt to privatise Aurora Energy's retail arm being abandoned in 2013. It aims to merge its transmission (Transend) and distribution (Aurora Energy) networks by 1 July 2014 to enhance operating efficiency.
- 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), 2010–11	MAXIMUM DEMAND (MW), 2010–11	REVENUE—CURRENT PERIOD ($ MILLION)[1]	ASSET BASE ($ MILLION)[2]	INVESTMENT—CURRENT PERIOD ($ MILLION)[1]	CURRENT REGULATORY PERIOD	OWNER
NEM REGION NETWORKS									
Powerlink	Qld	13 986	47 341	8 109	4 325	6 335	2 485	1 July 2012–30 June 2017	Queensland Government
TransGrid	NSW	13 957	70 828	13 760	4 000	4 540	2 650	1 July 2009–30 June 2014	New South Wales Government
SP AusNet	Vic	6553	52 352	9 982	3 005	2 395	840	1 Apr 2008–30 Mar 2014	Listed company (Singapore Power International 31%, State Grid Corporation 20%)[5]
ElectraNet	SA	5 591	13 045	3 570	1 430	2 020	685	1 July 2013–30 June 2018	State Grid Corporation 46.5%, YTL Power Investments 33.5%, Hastings Utilities Trust 20%
Transend	Tas	3 688	11 185	1 377	1 045	1 020	655	1 July 2009–30 June 2014	Tasmanian Government
NEM TOTALS		43 775	194 751		13 805	16 310	7 315		
INTERCONNECTORS[3]									
Directlink (Terranora)	Qld–NSW	63		180		140		1 July 2005–30 June 2015	Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)
Murraylink	Vic–SA	180		220	65	105	5	1 July 2013–30 June 2018	Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)
Basslink	Vic–Tas	375				920[4]		Unregulated	Publicly listed CitySpring Infrastructure Trust (Temasek 37%)

GWh, gigawatt hours; MW, megawatts.

1. Revenue and investment data are forecasts over the current regulatory period, converted to June 2012 dollars. The data are adjusted for the impact of merits review decisions by the Australian Competition Tribunal.
2. The regulated asset bases are as set at the beginning of the current regulatory period for each network, converted to June 2012 dollars.
3. Not all interconnectors are listed. The unlisted interconnectors, which form part of state based networks, are Heywood (Victoria–South Australia), QNI (Queensland–New South Wales) and New South Wales–Victoria.
4. Basslink is not regulated, so has no regulated asset base. The listed asset value is the estimated construction cost in 2012 dollars.
5. Singapore Power International contracted to sell a 20 per cent stake in SP AusNet to State Grid Corporation of China in 2013. The transaction was before the Foreign Investment Review Board in November 2013.

Sources: AER regulatory determinations and performance reports.

Table 2.2 Electricity distribution networks

NETWORK	CUSTOMER NUMBERS	LINE LENGTH (KM)	MAXIMUM DEMAND (MW), 2011–12	REVENUE—CURRENT PERIOD ($ MILLION)[1]	ASSET BASE ($ MILLION)[2]	INVESTMENT—CURRENT PERIOD ($ MILLION)[1,3]	CURRENT REGULATORY PERIOD	OWNER
QUEENSLAND								
Energex	1 333 670	51 432	4 464	7 065	8 220	6 040	1 July 2010–30 June 2015	Queensland Government
Ergon Energy	694 880	163 215	2 417	6 590	7 470	5 340	1 July 2010–30 June 2015	Queensland Government
NEW SOUTH WALES AND ACT								
AusGrid[4]	1 637 000	41 578	5 149	9 590	9 075	8 960	1 July 2009–30 June 2014	New South Wales Government
Endeavour Energy	883 663	34 569	3 236	4 830	3 970	3 190	1 July 2009–30 June 2014	New South Wales Government
Essential Energy	803 496	190 777	2 185	6 110	4 651	4 470	1 July 2009–30 June 2014	New South Wales Government
ActewAGL	173 186	4 992	674	800	645	330	1 July 2009–30 June 2014	ACTEW Corporation (ACT Government) 50%; Jemena (State Grid Corporation 60%, Singapore Power International 40%) 50%[5]
VICTORIA								
Powercor	734 523	85 310	2 161	2 500	2 285	1 620	1 Jan 2011–31 Dec 2015	Cheung Kong Infrastructure/ Power Assets 51%; Spark Infrastructure 49%
SP AusNet	649 634	49 287	1 577	2 405	2 170	1 528	1 Jan 2011–31 Dec 2015	Listed company (Singapore Power International 31%, State Grid Corporation 20%)[5]
United Energy	644 511	12 924	1 700	1 640	1 425	915	1 Jan 2011–31 Dec 2015	DUET Group 66%; Jemena (State Grid Corporation 60%, Singapore Power International 40%) 34%[5]
CitiPower	315 689	4 274	1 323	1 175	1 330	860	1 Jan 2011–31 Dec 2015	Cheung Kong Infrastructure/ Power Assets 51%; Spark Infrastructure 49%
Jemena	317 050	6 104	848	1 005	780	490	1 Jan 2011–31 Dec 2015	Jemena (State Grid Corporation 60%, Singapore Power International 40%)[5]
SOUTH AUSTRALIA								
SA Power Networks	832 072	87 648	2 715	3 715	2 895	2 250	1 July 2010–30 June 2015	Cheung Kong Infrastructure/ Power Assets 51%; Spark Infrastructure 49%
TASMANIA								
Aurora Energy	275 956	25 857	1 022	1 310	1 425	560	1 July 2012–30 June 2017	Tasmanian Government
NEM TOTALS	9 295 329	757 966		48 735	46 341	36 554		

1. Revenue and investment data are forecasts over the current regulatory period, converted to June 2012 dollars. The data are adjusted for the impact of merits review decisions by the Australian Competition Tribunal.
2. Asset valuation is the opening regulated asset base for the current regulatory period, converted to June 2012 dollars.
3. Investment 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.
4. AusGrid's distribution network includes 962 kilometres of transmission assets that are treated as distribution assets for economic regulation and performance assessment.
5. Singapore Power International contracted to sell a 60 per cent stake in Jemena, and a 20 per cent stake in SP AusNet, to State Grid Corporation of China in 2013. The transaction was before the Foreign Investment Review Board in November 2013.

Sources: AER and OTTER (Tasmania) regulatory determinations and performance reports.

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 $46 billion—almost three times the valuation for transmission infrastructure (around $16 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 Queensland transmission network (2012–17) and Victorian distribution networks (2011–15).

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. The range of control mechanisms is wider in distribution; the AER may set a ceiling on the revenue or prices that a distribution business can earn or charge during a period. The available mechanisms for distribution include:

- weighted average price caps, allowing flexibility in individual tariffs within an overall ceiling—used for the New South Wales, 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.

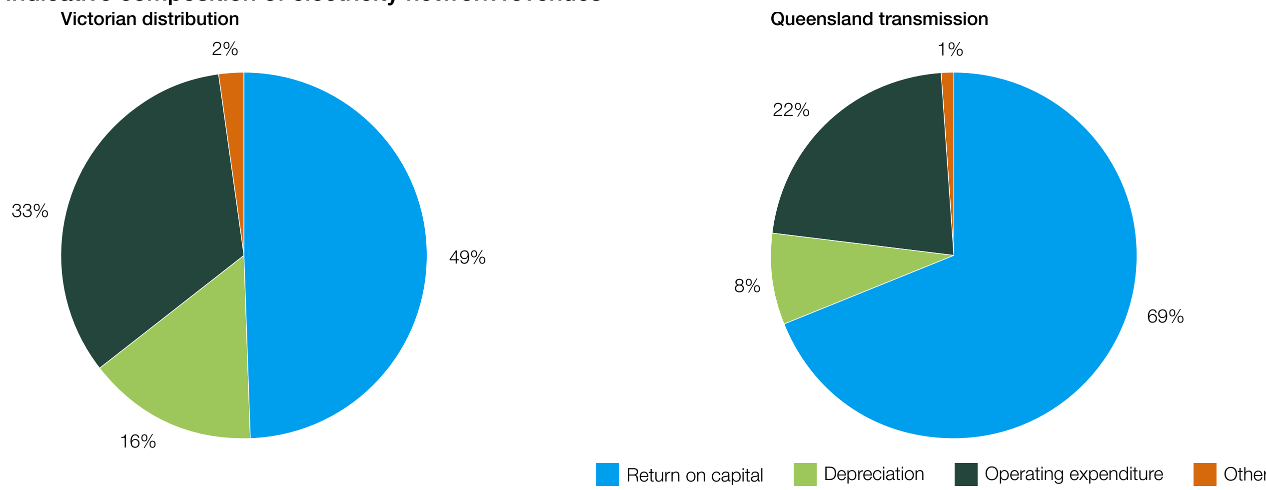
The regulatory process for network businesses was revised under a rule change in November 2012. It begins with preliminary consultation on the framework and approach for the determination, around two years before the current regulatory period expires. The network business then submits a regulatory proposal to the AER, which assesses the proposal in consultation with stakeholders (section 2.2.2). 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

In 2011 the AER proposed changes to the energy rules to ensure customers pay no more than necessary for an economically efficient and reliable supply of energy. Following detailed public consultation, the Australian Energy Market Commission (AEMC) in November 2012 announced significant reforms to the rules for setting energy network prices. The reforms aim to better meet the long term interests of consumers, while providing investment certainty in a dynamic market environment. They do so by:

Figure 2.2

Indicative composition of electricity network revenues



Source: AER.

- creating a common approach to setting the cost of capital across electricity and gas network businesses, based on the rate of return for a benchmark efficient service provider
- providing new tools to (a) incentivise electricity network businesses to invest efficiently, (b) safeguard consumers from paying for inefficient expenditure, and (c) ensure efficiency benefits are shared between consumers and service providers
- strengthening stakeholder involvement in the regulatory review of electricity networks.

In December 2012 the AER launched the Better Regulation program to apply the reforms, the scope of which is outlined in table 2.3. It published guidelines during 2013 on its approach to implementation. The new guidelines and related schemes will apply first to regulatory determinations taking effect in 2015 for electricity transmission networks in New South Wales and Tasmania, and for electricity distribution networks in New South Wales, Queensland, South Australia and the ACT.

The Better Regulation program also covers wider refinements to the AER's regulatory approach, including:

- the application of a new regulatory investment test for distribution networks (RIT-D, section 2.4.1)
- reforms arising from the AEMC's *Power of choice* review (section 2.6.1)
- the development of benchmarking techniques and tools in regulatory decisions
- more consistent information requirements on energy business, to improve the quality of data for regulatory reviews and annual performance reporting, and to support the use of benchmarking.

The Productivity Commission in 2013 also reviewed the use of benchmarking in network regulation. It found benchmarking is not yet capable of replacing the current framework for setting network revenues, but could be used to test network business proposals.[2]

2.2.3 Regulatory timelines and recent AER activity

Figure 2.3 shows the regulatory timelines for electricity networks in each jurisdiction. In 2013 the AER:

- published final determinations for ElectraNet (South Australian transmission) and Murraylink (the transmission interconnector between Victoria and South Australia), covering the regulatory period commencing 1 July 2013
- released a draft determination in August 2013 for SP AusNet (Victorian transmission), covering the regulatory period commencing 1 April 2014

2 Productivity Commission, *Electricity networks regulatory framework, inquiry report*, April 2013.

Table 2.3 Changes to the regulatory process under Better Regulation

REFORM	WHAT HAS CHANGED?	PURPOSE	AER ACTIVITY
Greater stakeholder involvement in regulatory reviews	Creation of a Consumer Challenge Panel to assess whether: • regulatory proposals are in the long term interests of consumers • network businesses are engaging effectively with customers The review process has been extended by four months and the AER and network businesses must provide more information to stakeholders at an early stage The AER may consider how a business has engaged with its consumers when setting expenditure allowances Clearer guidelines on types of information submitted by network businesses that may be treated as confidential	Strengthen accountability that regulatory reviews meet the national electricity objective to promote the long term interests of consumers Address concerns that confidentiality provisions have allowed network businesses to strategically withhold or limit scrutiny of key information	Consumer Challenge Panel established 1 July 2013 Consumer engagement guideline published October 2013 Confidentiality guideline published November 2013
Stronger powers for the AER to assess and amend network spending proposals	The AER can apply new tools and techniques to better forecast how much network businesses need to spend It is no longer limited to a narrow assessment of a network business's proposal The new tools include benchmarking and trend techniques to test expenditure proposals and compare the relative performance of each business	Under the old rules the AER was required to assess expenditure forecasts on the basis of the business's proposal, usually requiring a detailed bottom-up assessment. The AER was limited to amending forecasts only to the extent necessary for compliance with the rules; this created an upward bias in revenue allowances	Expenditure assessment guideline published November 2013
New approach to setting rates of return for network businesses	A common approach now applies for setting the cost of capital across all electricity and gas network businesses, based on the costs for a benchmark efficient service provider The AER's assessment can account for a wider range of information than previously, and allows for decisions that better reflect conditions in capital markets The AER must undertake a full public review of its approach at least every three years	The old rules provided separate rate of return frameworks for electricity distribution, electricity transmission, and gas pipelines The AER was locked into a parameter-by-parameter assessment of the rate of return, with limited scope to consider the appropriateness of the overall allowance	Rate of return guideline scheduled for publication December 2013

REFORM	WHAT HAS CHANGED?	PURPOSE	AER ACTIVITY
New incentives for efficient investment	A new incentive scheme ensures efficiency benefits are shared between consumers and network businesses The AER can assess overspends in capital expenditure allowances, and can exclude inefficient overspends from the regulated asset base	Under the old rules an efficiency benefit sharing scheme applied to operating expenditure but not capital expenditure All capital expenditure was automatically rolled into the regulated asset base, creating an incentive to overspend	Expenditure incentives guideline published November 2013
Fairer arrangements for distribution of revenue from shared assets	Revenue earned by network businesses from third party use of regulated assets will be shared with customers, for example by reducing regulated revenue allowances	Under the old rules revenues earned from third party use of network assets were not shared with consumer, despite consumers being required to wholly fund the assets	Shared assets guideline published November 2013

- began preparing for reviews of the New South Wales and ACT distribution businesses, and the New South Wales and Tasmanian transmission businesses, covering regulatory periods commencing 1 July 2014. These businesses will operate under transitional arrangements for the year commencing 1 July 2014, with a full determination under the new rules to cover the remaining four years.
- began preparing for reviews of the Queensland and South Australian distribution businesses, and Directlink (transmission interconnector between Queensland and New South Wales), covering regulatory periods commencing 1 July 2015.

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]

The AER in 2013 commenced a review (expected to be completed by September 2014) of its network pricing guideline for transmission businesses. This review followed an AEMC rule change on interregional charging arrangements for transmission networks, to provide more efficient price signals. Currently, 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 new charging arrangements, which take effect from 1 July 2015, introduce a modified load export charge that effectively treats the business in the importing region as a customer of the business in the exporting region.

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 the whole determination.

To have a decision amended, the network business must demonstrate the AER:

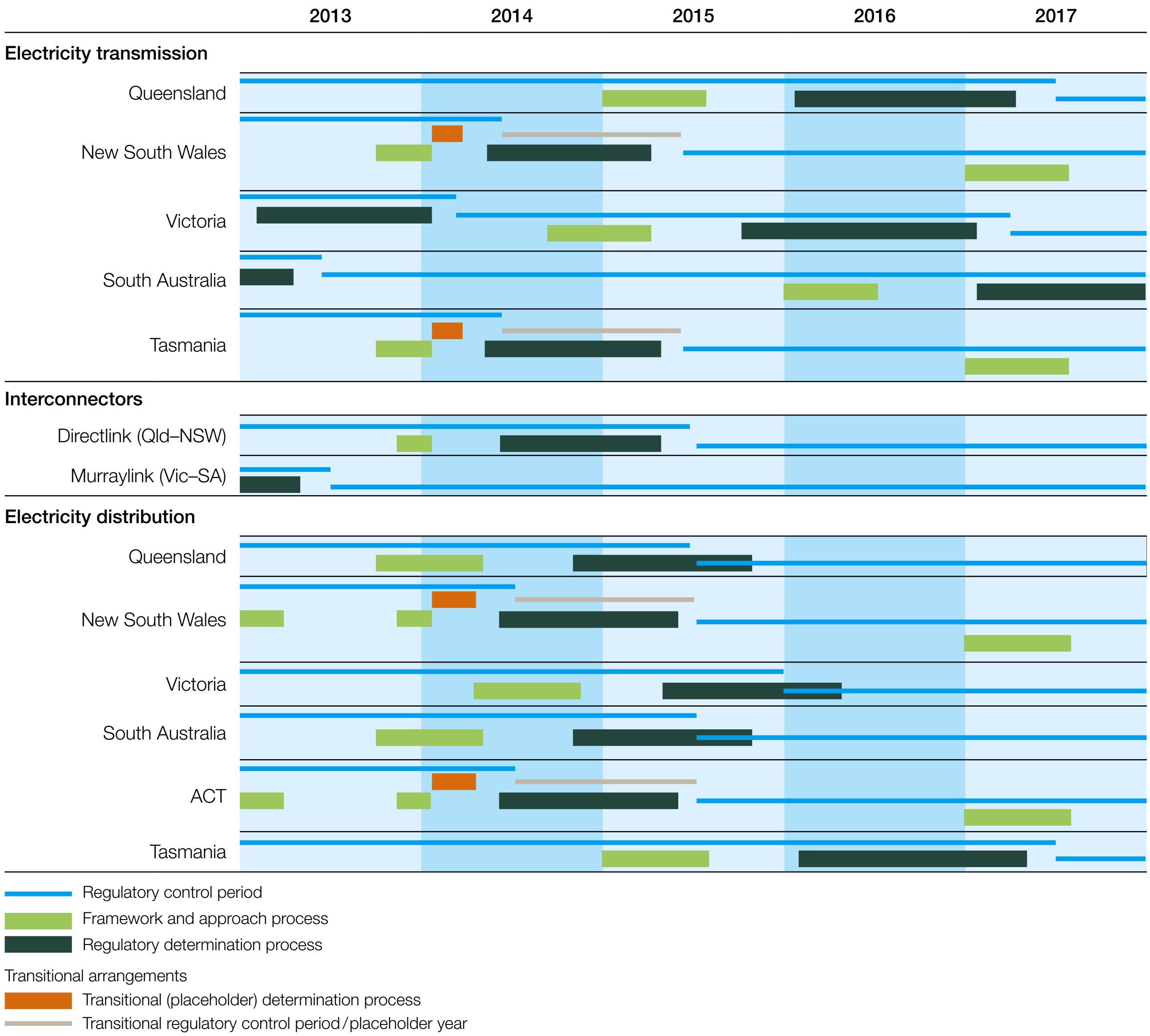
- made an error of fact that was material to its decision
- incorrectly exercised its discretion, having regard to all the circumstances, or
- made an unreasonable decision, having regard to all the circumstances.

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

Between June 2008 and June 2013 network businesses sought review of 18 AER determinations on electricity networks—three reviews in transmission and 15 in

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

Figure 2.3
Indicative timelines for AER determinations on electricity networks



Source: AER.

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.

In April 2012 the Tribunal remitted back to the AER elements of the determination on advanced metering infrastructure costs for Victoria's SP AusNet distribution network. SP AusNet had sought significant price increases to recover unanticipated costs relating to its choice of communications technology. The AER's revised decision in February 2013 again rejected the price increases sought. Following an appeal by SP AusNet, the Tribunal in August 2013 affirmed the AER's decision. In September 2013, SP AusNet appealed the Tribunal's decision to the full Federal Court.

At October 2013 no electricity matters were before the Tribunal.

Changes to merits review arrangements

In 2012 an independent review of the limited merits review regime found the regime has not operated as intended. It found the regime:

- does not sufficiently consider the national electricity and gas objectives, which focus on the long term interests of consumers
- focuses on the matters raised for review, without sufficiently considering the overall balance of a determination.

In response, the SCER in September 2013 agreed to amendments that will require:

- a network business to demonstrate that 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 Tribunal to consider any matters interlinked with the grounds of the appeal, and to consult with relevant users and consumers.

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).

Legislation to implement these changes was passed by the South Australian Parliament in November 2013. A further review of the regime will commence in 2016.

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 over $62 billion for the current regulatory cycle, comprising over $14 billion for transmission and $49 billion for distribution—a 43 per cent real increase from the revenue allowances in previous regulatory periods. Revenue growth is flatter, however, for more recent determinations.

The main revenue drivers are capital financing, capital expenditure (section 2.4) and operating costs (section 2.5). 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 the period 1 July 2013–30 June 2018 would have resulted in an 8 per cent increase in revenue.

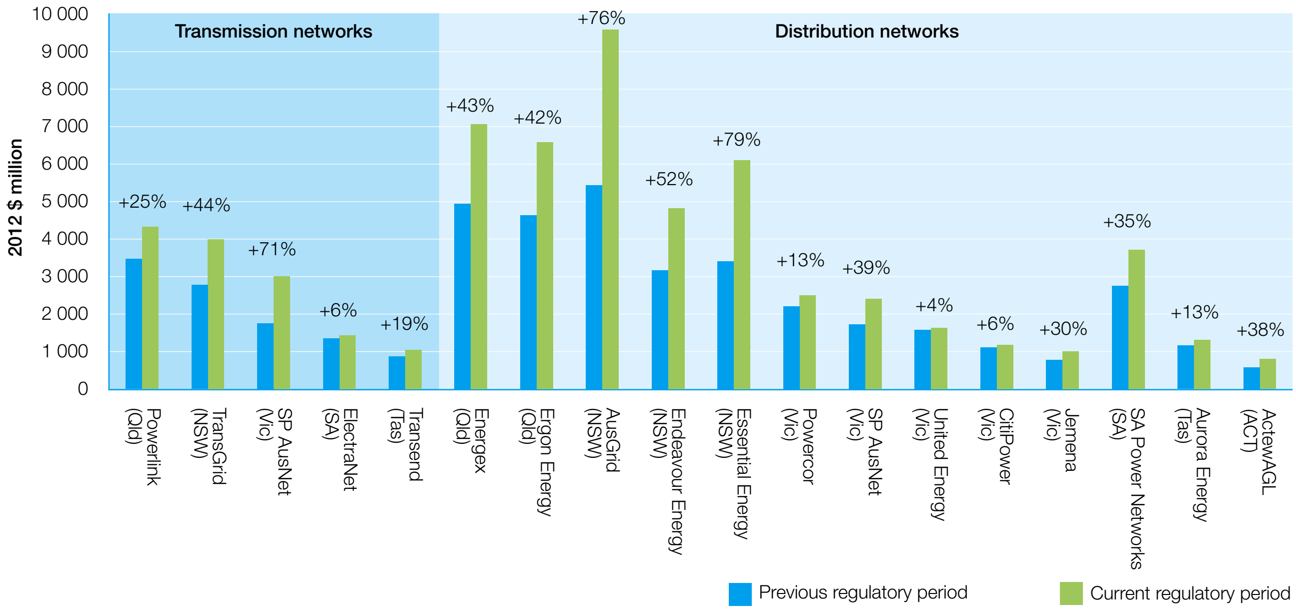
For AER determinations made from 2009 to 2011, the forecast cost of capital used to set revenue allowances was generally higher than in previous regulatory periods (figure 2.5). The primary factor underpinning the increases was a higher debt risk premium, which reflects the cost of borrowing for a business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

AER determinations made since 2012 reflect recent reductions in the risk free rate and market and debt risk premiums, which lowered the overall cost of capital. The overall cost of capital in determinations made in 2013 was 7–7.5 per cent, compared with up to 10.4 per cent in 2010.

The Tribunal's decision to amend the value adopted for tax imputation credits (gamma) for the Queensland and South Australian distribution networks increased revenue allowances. The decision also had impacts on other determinations.

Figure 2.4

Electricity network revenue



Notes:

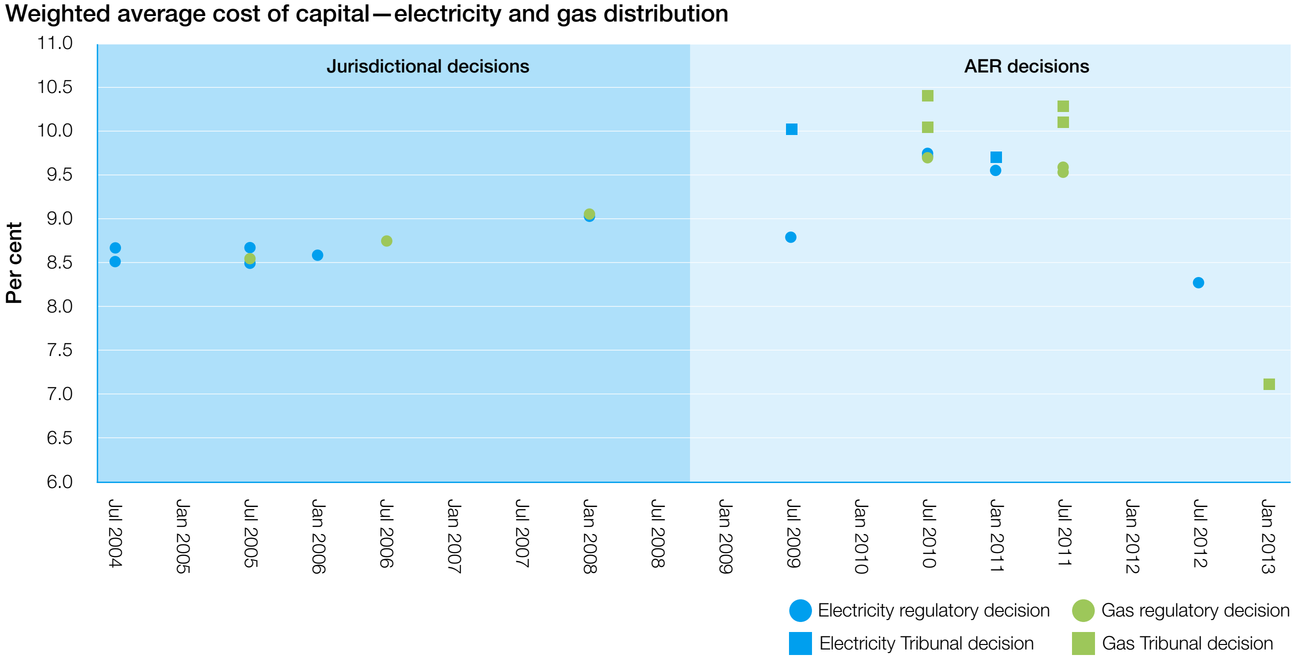
Current regulatory period revenues are forecasts in regulatory determinations, amended for merits review decisions by the Australian Competition Tribunal.

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.

Figure 2.5

Weighted average cost of capital—electricity and gas distribution



Note: Nominal vanilla weighted average cost of capital.

Source: AER.

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.

In 2013 the AEMC proposed to enhance transmission planning by allowing AEMO to review network planning reports and the regulatory investment test for transmission (RIT-T) processes (section 2.4.1), and to provide demand forecasts. Transmission businesses would have more input into the planning process, and would consult with each other and the national transmission planner on projects with interregional impacts. Aligning regulatory control periods for transmission business would also help planning.

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. Until 2010 the assessment entailed a common regulatory test for both transmission and distribution. The test required a business to determine whether a proposed augmentation passes a cost–benefit analysis or provides a least cost solution to meet network reliability standards.[5] New tests for transmission and distribution businesses have replaced the original regulatory test.

The regulatory investment test for transmission (RIT-T), introduced in August 2010, applies to a wider range of projects than did the previous test and assesses transmission proposals against a market based cost–benefit analysis. A network business must identify the purpose of a proposed investment and assess it against all credible options for achieving that purpose. The business must publicly consult on its proposal; affected parties can lodge a dispute.

A new regulatory investment test for distribution (RIT-D) will commence on 1 January 2014. The RIT-D is similar to the RIT-T, but requires network businesses to assess investment proposals against a different set of market benefits. It applies to investment projects over $5 million and includes a dispute resolution process. The RIT-D is part of a new national framework for electricity distribution network planning and expansion. That framework also requires distribution businesses to release annual planning reports and maintain a demand side engagement strategy.

The AER's roles in relation to regulatory investment tests include:

- publishing the tests and guidelines—the AER published the RIT-D and related material in August 2013
- helping resolve disputes over how the tests are applied
- monitoring and enforcing compliance—the AER conducted a number of compliance reviews in 2013
- periodically reviewing project cost thresholds—the AER completed a review for the RIT-T in November 2012
- determining whether a preferred investment option meets the RIT-T's cost–benefit analysis, on request from the business that conducted the test. This role does not apply to reliability driven projects.

A number of RIT-T and regulatory test processes have occurred since July 2012, including for the following projects:

- ElectraNet and AEMO (the transmission network planner for Victoria) assessed the viability of upgrading the Heywood interconnector between Victoria and South Australia. The final report in January 2013 found the upgrade would provide additional energy supply to South Australia at times of maximum (summer) demand; allow more efficient generation dispatch in Victoria and South Australia; and promote new investment in low fuel cost generation. The project was estimated to have net benefits of up to $190 million. Because the project's purpose was not to meet reliability standards, ElectraNet requested the AER make a determination confirming the project passed a cost–benefit analysis. The AER confirmed in September 2013 that the project satisfied the RIT-T.
- Powerlink and TransGrid consulted on a method to assess the competition benefits of a proposed upgrade to the Queensland–New South Wales interconnector

5 AER, *Regulatory test for network augmentation, version 3*, 2007.

(QNI). The businesses consider market benefits arise from allowing generation capacity in one region to meet peak demand in another. A previous test in 2008 found an upgrade would not be required until 2015–16.

- Powerlink assessed options to meet increased demand from new coal mine developments in the Bowen Basin. It found 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.
- AEMO published draft reports assessing projects to meet rising demand in regional Victoria and eastern metropolitan Melbourne.

Since July 2012 NEM demand forecasts have eased in most regions, meaning a number of planned investments are no longer required. Projects that passed a regulatory investment test but were then deferred include TransGrid projects for new transmission infrastructure between Dumaresq and Lismore, and for a network expansion on the mid north coast of New South Wales.

Ergon Energy's planned line from Warwick to Stanthorpe was also deferred. The project had been subject to a regulatory test, but an AER review found the test's application was flawed. Ergon Energy committed to reassess the project closer to when it is required.

A number of RIT-T processes have also been terminated or deferred:

- ElectraNet deferred its assessment of options to address rising demand in the Lower Eyre Peninsula until it knows whether mining developments in the area will proceed.
- ElectraNet deferred its assessment of options to address voltage limitations in the mid-north of South Australia. The project was initially forecast to be required for summer 2015–16, but that timeframe was extended to 2024.
- AEMO terminated its assessment of options to address emerging voltage stability limitations in regional Victoria. Weaker demand forecasts mean these limitations are now unlikely to arise.

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 five year cycle is forecast at over $7 billion for transmission networks and $36 billion for distribution networks. These forecasts represent an increase on investment in the previous regulatory periods of around 16 per cent in transmission and 60 per cent in distribution (in real terms). Determinations made since 2012 reflect a different investment trend.

Changes in operating environments, even over a relatively short period, can cause significant variations in investment requirements. A number of active AER determinations that were made several years ago reflected increased capital needs to replace ageing assets, meet higher reliability and new bushfire (safety) standards, and respond to forecasts made at the time of rising peak demand.

The determination for the AusGrid distribution network in New South Wales for 2009–14, for example, provided for capital investment to meet an expected increase in peak demand from 5500 to 6700 megawatts over the period.[6] But these forecasts proved optimistic; actual peak demand over the first four years of the period did not surpass 6000 megawatts, and the forecast for 2013–14 is below this level.[7]

With around 25 per cent of capital expenditure for distribution businesses driven by growth in electricity demand (compared with 60 per cent for transmission), this lower level of demand means businesses can defer a significant amount of allowed expenditure for the period. While customers will benefit from the deferral of investment, they still bear costs during the current period based on the higher forecast expenditure level.

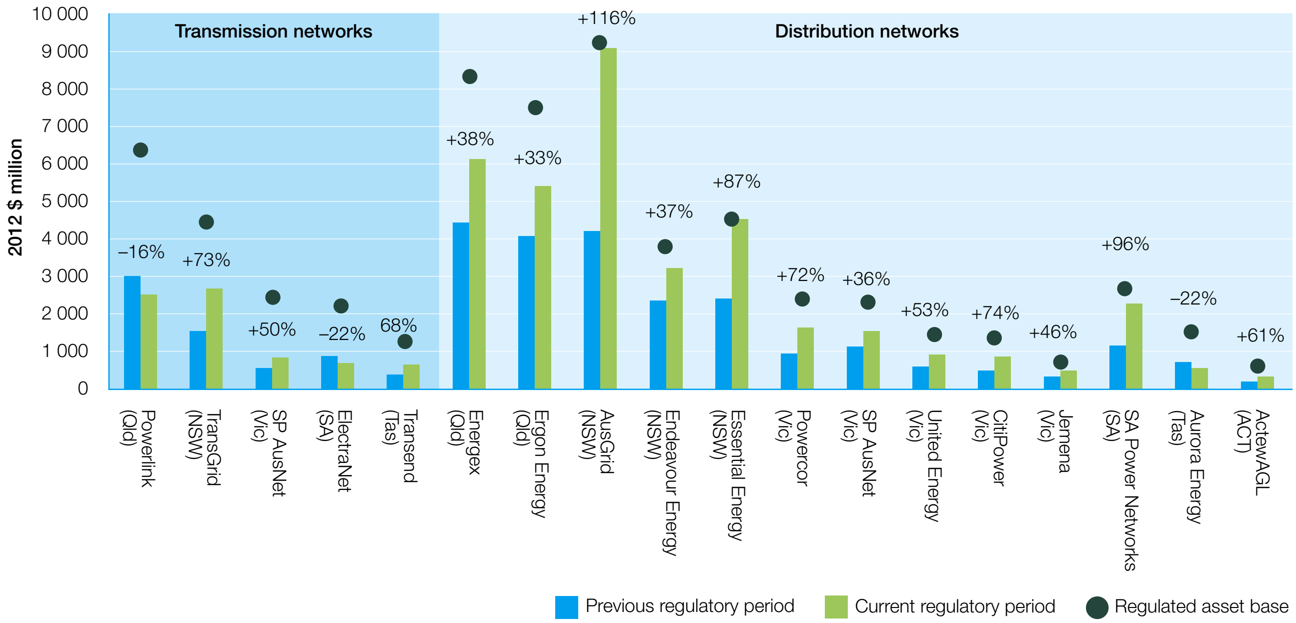
More recent determinations reflect this moderation in forecast growth in industrial and residential energy use, including peak demand (section 1.1). The AER found revisions to forecast load growth for ElectraNet, for example, meant the business did not require demand driven investment over the regulatory period, reducing its original expenditure proposal by $132 million. However, the determination includes 11 contingent projects, allowing for capital expenditure to cover rises in demand associated with defined trigger events.

New tools available to the AER through the Better Regulation program promote efficient capital expenditure. A capital efficiency benefit sharing scheme will provide

6 AER, *New South Wales distribution determination 2009–10 to 2013–14, final decision*, 2009.

7 AusGrid, *Transmission annual planning report 2013*.

Figure 2.6
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), 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.

businesses with an incentive to undertake efficient capital expenditure, because they can retain a share of the gains (section 2.5.1). The AER will also be able to review any capital overspend. Any inefficient expenditure will be excluded from the business's asset base (meaning consumers will not pay for it).

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.

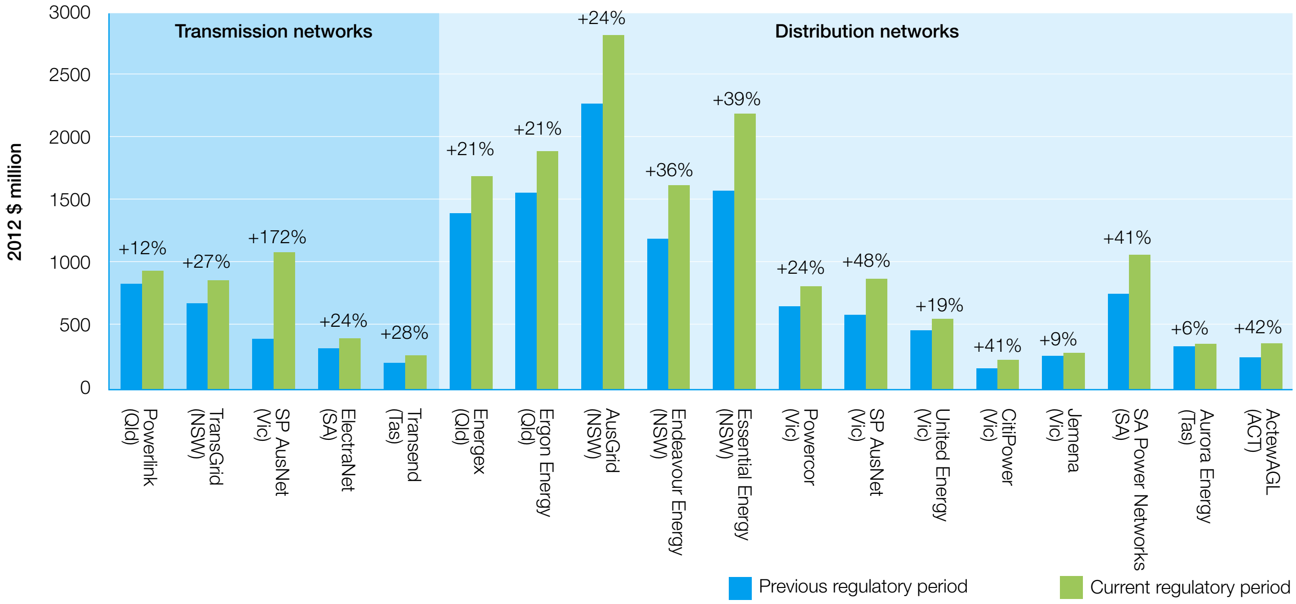
Figure 2.7 illustrates operating and maintenance expenditure allowances for electricity networks in the current five year regulatory periods compared with previous regulatory periods. In the current cycle, transmission businesses in the NEM are forecast to spend $3.6 billion on operating and maintenance costs. Distribution businesses are forecast to spend almost $15 billion.

Differences in the networks' operating environments result in significant variations in expenditure allowances. On average, costs are forecast to rise by 45 per cent in transmission and 28 per cent in distribution for the current regulatory periods, compared with previous regulatory periods.

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. Operating cost increases may also reflect step change factors—that is, new business requirements that were not part of the previous regulatory period. The 2010 Victorian determinations, for example, had to account for an expected increase in regulatory compliance costs for electrical safety, network planning and customer communications, stemming from government decisions following the 2009 Victorian bushfires.

Figure 2.7

Operating expenditure of electricity networks



Notes:

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

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

Sources: Regulatory determinations by the AER.

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 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. 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.

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.

2.6 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.

2.6.1 *Power of choice* review

The AEMC in November 2012 completed its *Power of choice* review into efficient alternatives to network investment to deal with rising peak demand. It recommended:

- improving price signalling to customers, by introducing time varying network tariffs and continuing the rollout of interval metering (section 2.6.2)
- removing barriers to large consumers offering demand reduction into the wholesale electricity market

- providing more flexibility for consumers to access their own consumption data, and a framework for consumer engagement with demand side providers
- modifying the AER's demand management incentive scheme to capture wider market benefits and network deferral benefits beyond the current regulatory period
- considering, when the AER develops its national ring fencing guidelines, the benefits of allowing network businesses to own and operate generation plant connected to their networks
- enabling consumers to sell small scale generation (for example, solar or battery storage) to parties other than their electricity retailer, and to unbundle the provision of non-energy services (including ancillary services) from the supply of electricity.

The Council of Australian Governments (CoAG) in December 2012 approved the adoption in principle of the full set of *Power of choice* recommendations. Energy ministers tasked AEMO with developing and submitting rule change proposals by 2015 on recommendations relating to the wholesale market. AEMO released design proposals in August 2013 (section 1.10). Progress has also occurred with recommendations relating to the network sector, as outlined in sections 2.6.2 and 2.6.3.

2.6.2 Metering and smart grids

Interval meters—with time based data on energy use and communication capabilities for remote reading and customer connection to the network—are central to many *Power of choice* recommendations. This type of metering, when coupled with time varying prices, can encourage customers to actively manage their electricity use.

The *Power of choice* review recommended all new meters installed for residential and small businesses consumers be interval meters with remote communication capacity. It proposed accelerating the installation of new metering for large residential and small business consumers.

The AEMC proposed that network businesses be required to adopt time varying pricing in setting network charges. That requirement would encourage retailers to reflect those charges in customer contracts. In response, the SCER in September 2013 submitted a rule change proposal to change the distribution network pricing principles. The changes would encourage distribution businesses to set cost reflective network prices, which would provide more efficient pricing signals to consumers.

The Victorian Government expects to complete a rollout of interval meters with remote communications to all customers in 2014. From September 2013 small customers have been offered the choice of moving to more flexible tariff structures. Customers electing to switch to time varying prices have the option until March 2015 of reverting to a single rate tariff.

Interval meter costs have been progressively passed on to Victorian retail customers since 1 January 2010. Network charges increased by almost $80 for a typical small retail customer by 2012, with further annual increases of $9–21 for 2012–15.[8] Outside Victoria, no large scale rollout of interval meters has commenced; however, a number of distribution network businesses are installing interval meters (so far, over 1.5 million) on a new and replacement basis.[9]

2.6.3 Other demand management initiatives

The AER applies incentives that enable distribution network businesses to investigate and implement non-network approaches to manage demand. These approaches may include measures to reduce demand or provide alternative ways of meeting 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 SCER in 2013 was developing a rule change proposal on the incentive scheme.

The AEMC published a draft rule in July 2013 to streamline the process for connecting generators to the distribution network. The new rule establishes clearer enquiry and application processes, and sets out new information requirements. Distribution businesses will be required to provide connection applicants with example costs, a model connection agreement and information on technical requirements. The AEMC expects to finalise the rule change in December 2013.

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

9 Department of Resources, Energy and Tourism, *National smart meter infrastructure report*, February 2013.

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 2011–12 caused less than three minutes of unsupplied energy in New South Wales, Victoria and South Australia; Tasmania had around nine minutes of unsupplied energy. No data were published for Queensland. Performance has been relatively consistent over recent years.[10]

Transmission reliability standards

State and territory agencies determine transmission reliability standards. The SCER 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 distribution framework in September 2013, and on the transmission framework in November 2013.[11] The frameworks contain common features, including that jurisdictions would remain responsible for setting reliability standards (with the option of delegating to the AER), based on a transparent economic assessment and community consultation. The AEMC recommended reliability standards be set every five years, to align with the regulatory determination process, but with flexibility to adjust to reflect new information.

10 ESAA, *Electricity gas Australia 2013*.

11 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.

It also recommended a national approach to reporting on reliability performance. In August 2013 AEMO finalised a method for estimating the value of customer reliability, and it will develop the associated values by March 2014. Under the recommended approach, the AER would assume responsibility for developing the values of customer reliability for each jurisdiction every five years. To ensure the framework is consistently applied, the AER would develop a guideline on the economic assessment process and its key assumptions.

For transmission businesses, reliability standards will be defined on an input basis, but with the potential for jurisdictions to supplement these standards with output measures. Reliability measures for distribution businesses will be defined on an output basis and linked to the AER's service target performance incentive scheme (section 2.8.3).

2.7.2 Transmission network congestion

Physical 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, maintenance and operating procedures, and standards for network capability (such as thermal, voltage and stability limits). Factors beyond the control of the business 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 occurs on just a few days, and is largely attributable to network outages.

A major transmission outage in combination 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 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 lead to disorderly bidding in the wholesale market, and to inefficient electricity trade flows between the regions (section 1.6).

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 an incentive scheme to encourage network businesses to apply relatively low cost solutions to congestion.

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 2.9.1).

2.7.3 Service target performance incentive scheme—transmission

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

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

Rather than impose a common benchmark target, the AER sets separate standards that reflect the circumstances of each network based on its past performance. 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.

The scheme includes a separate component based on the market impact of transmission congestion, which encourages a network to make relatively low cost improvements to its operating practices to reduce congestion. These practices may include more efficient outage timing and notification, 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 a further 2 per cent of its regulated revenue if it eliminates all outage events with a market impact of over $10 per megawatt hour.

The results are standardised for each network to derive an 's factor' that can range between –1 (the maximum penalty) and +3 (the maximum bonus). Table 2.4 sets out s factors for each network for the past six years. While performance against individual component targets has varied, the networks generally received financial bonuses for overall performance. TransGrid, ElectraNet and Directlink received financial penalties in 2012 relating to the service component of the scheme. Underperformance was most common in relation to transmission circuit availability targets.

The performance of ElectraNet and TransGrid in 2012 was weaker than in the previous year. ElectraNet's overall transmission circuit availability fell, while TransGrid had a reduction in transformer availability and took longer on average to restore supply after an outage. Transend performed significantly better in 2012 than in the previous year, improving the availability of critical transmission circuits and reducing supply outages.

TransGrid, Powerlink, ElectraNet and SP AusNet applied the congestion component of the scheme in 2012. Transmission congestion as a result of network outages in 2010–12 was negligible in Queensland and low in New South Wales. Congestion was also significantly lower compared with levels recorded in the previous benchmark period. Transmission congestion in Victoria improved in 2012 compared with the previous year, but worsened in South Australia. Increased congestion on the ElectraNet network was driven by network outages surrounding North West Bend. Payments under the congestion component in 2012 were $33 million, up from $27 million in 2011.

The AER in December 2012 enhanced incentives for transmission businesses to improve network performance. It revised the incentive scheme to consist of:

- a *service component*, with an incentive of +/– 1 per cent of regulated revenue. This component focuses on the frequency of interruptions to supply, the duration of outages, and the number of unplanned faults on the network. It also covers protection and control equipment failures.
- a *market impact component*, with an incentive of 0–2 per cent of regulated revenue. The AER will assess this component differently under the new version of the scheme, measuring a network's performance over two years against outcomes over the previous three years.
- a *network capability component*, with an incentive of up to 1.5 per cent of regulated revenue. Payments are made to fund one-off projects that improve the capability, availability or reliability of the network at times most needed. The total cost of projects funded through this component cannot exceed 1 per cent of the network's revenue. AEMO will help prioritise the projects to deliver best value for money for consumers, and the AER will approve the project list. Network businesses will be subject to 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 new scheme is expected to apply first under regulatory determinations for SP AusNet, Transend and TransGrid that commence in 2014.

Table 2.4 S factor values

			2008		2009	2010	2011		2012
Powerlink (Qld)	Service component		0.53		0.17	0.65	0.42	0.44	0.45
	Market impact component					1.97	1.95	1.98	2.00
TransGrid (NSW)	Service component		0.31	0.22	–0.28	–0.24	–0.13		–0.49
	Market impact component				0.39	1.45	1.39		1.48
AusGrid (NSW)	Service component		0.72		0.37				
SP AusNet (Vic)	Service component	0.15	0.82		0.51	0.58	0.72		0.82
	Market impact component						0.00		0.80
ElectraNet (SA)	Service component	0.29	–0.40		0.60	0.00	0.32		–0.30
	Market impact component						0.52		0.00
Transend (Tas)	Service component		0.85	0.88	0.11	0.35	–0.41		0.33
Directlink (Qld–NSW)	Service component		–1.00		–0.98	–1.00	–0.87		–1.00
Murraylink (Vic–SA)	Service component		0.69		0.87	1.00	0.70		0.92

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.

Powerlink reported separately for the first and second halves of 2012.

Source: AER, *Transmission network service providers: electricity performance report for 2010–11*, 2012.

2.7.4 Transmission frameworks review

The AEMC in April 2013 completed a review of how electricity transmission services are provided and used. Among its recommendations were proposals to streamline arrangements for connecting generators to the transmission network, and to progress the design of an 'optional firm access' model to manage risks associated with network congestion.

Connections

The review 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.

Optional firm access

Generators face the risk of network congestion constraining the dispatch of their plant. To better manage this risk, the AEMC proposed an optional firm access model under which generators would pay transmission businesses to secure firm network access. Transmission businesses would plan and operate their networks to provide the agreed capacity, with their charge to generators reflecting the cost of providing that capacity. If congestion prevents a generator with firm access from being dispatched, then non-firm generators that contributed to the congestion would compensate the firm generator for any loss.

The model would also allow 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 would require generators, when deciding where to locate new plant, to account for trade-offs between congestion costs and the costs of funding network expansions. As a result, generation and transmission investment would likely become more efficient. The model would also provide incentives for transmission businesses to maximise network availability when it is most valuable to the market.

The AEMC also noted the model's potential benefits for wholesale market participants, in supporting contracting between generators and retailers across regions and reducing dispatch risk for generators. It estimated optional firm access would take four years to implement.

2.8 Distribution network performance

Measures of performance for electricity distribution networks include:

- the reliability of supply
- 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.

Distribution outages account for over 95 per cent of electricity outages in the NEM. 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, distribution outages should be kept to efficient levels—based on the value of reliability to the community and the willingness of customers to pay—rather than trying to eliminate every possible interruption.

State and territory governments determine distribution reliability standards. The trade-off between reliability and cost means a government decision to increase reliability standards may require substantial new investment that affects customer bills. An AEMC assessment for New South Wales found a reduction in reliability standards that increased network outages by 2–15 minutes per year would save an average consumer $3–15 per year. It concluded the savings outweighed the impact of slightly weaker reliability.[12]

Concerns about the impact of network investment on retail electricity prices led CoAG in December 2012 to agree a new best practice approach was needed to set distribution reliability standards. Energy ministers directed the AEMC to develop a national framework by the end of 2013 (section 2.7.1). As a result, the AEMC in September 2013 proposed a new approach to setting distribution reliability targets.

The proposed process would weigh the cost of new investment against the value that customers place on reliability and the likelihood of interruptions, to help set efficient reliability targets. The assessment would be transparent and independent of the network provider. The AER's service target performance incentive scheme would provide incentives for network businesses to meet their reliability targets.

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.

Figure 2.8 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 experiences around 200–250 minutes of outages per year, but with significant regional variations.

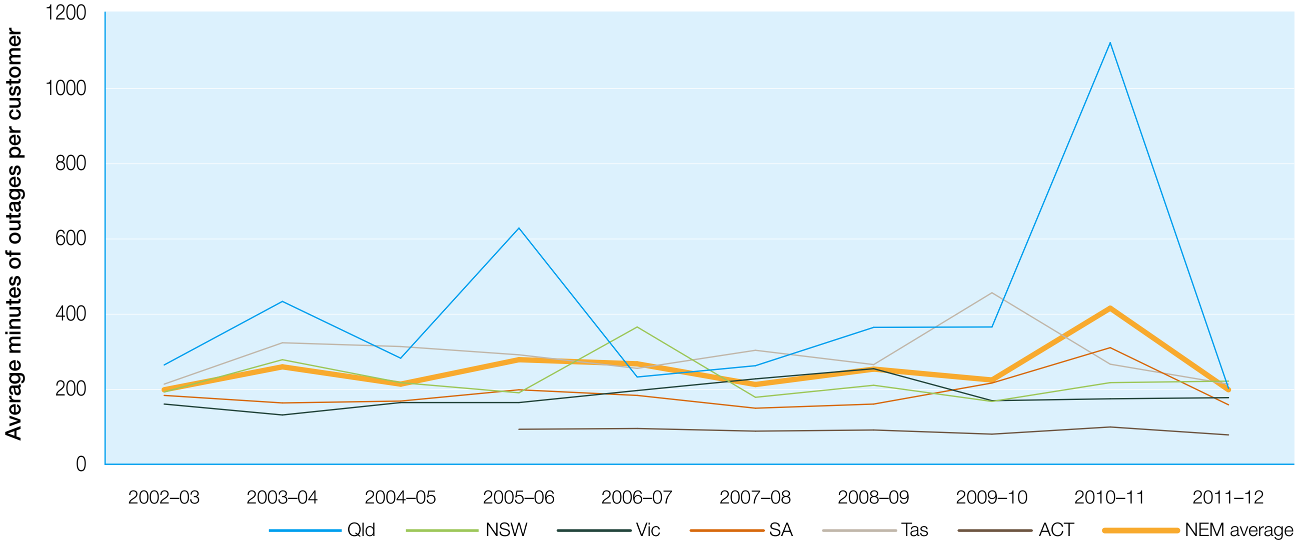
In 2011–12 the average duration of outages per customer was consistent with that of the previous year in New

12 AEMC, *Review of distribution reliability outcomes and standards, final report—NSW workstream*, 2012.

Figure 2.8

System reliability

SAIDI



SAIFI

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 (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.

South Wales and Victoria, and fell in all other jurisdictions. Average outage duration across the NEM was the lowest in a decade, partly due to less extreme weather activity. The largest reduction in outages occurred in Queensland, where an average customer experienced around 200 minutes of outages in 2011–12—down from 1122 minutes in 2010–11 when severe flooding in the south east, and Cyclone Yasi in the north, affected performance on both the Energex and Ergon Energy networks. 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 was relatively stable between 2002–03 and 2011–12, with energy customers across the NEM experiencing an outage around twice a year. The average frequency of outages in 2011–12 was reduced or stable relative to that of the previous year in all jurisdictions. Queensland and South Australia recorded the largest reductions in outage frequency.

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 2.8 are relevant. But, in assessing network performance, the AER normalises data to exclude interruption sources beyond the network's reasonable control.

In 2011–12 New South Wales and ACT network businesses were not subject to the scheme. Most other businesses met outage duration and frequency targets. Three businesses—Ergon Energy, CitiPower and United Energy—underperformed against their outage duration targets. CitiPower and United Energy also missed their targets for the average frequency of outages.

2.8.2 Customer service—distribution

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 related data. It shows customer service outcomes in 2011–12 broadly aligned with those of previous years. Aurora Energy (Tasmania) and SP AusNet (Victoria) recorded the highest proportion of late connections, but each network performed better than in the previous year. Call centre responsiveness fell for all New South Wales networks; AusGrid recorded the worst performance, answering less than half of all calls within 30 seconds.

2.8.3 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 (section 2.8.1) and customer service (section 2.8.2). A guaranteed service level (GSL) component provides for a business to pay customers if its performance falls below threshold levels.[13]

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.[14] 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 New South Wales 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. All businesses outperformed their targets for 2012. Incentive payments ranged from $10 000 for CitiPower to almost $2.5 million for Powercor.

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

14 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				
	2007–08	2008–09	2009–10	2010–11	2011–12	2007–08	2008–09	2009–10	2010–11	2011–12
QUEENSLAND[1]										
Energex	10.8	2.5	0.4	0.9	0.3	96.3	89.7	90.0	86.6	88.6
Ergon Energy	0.7	0.3	0.4	1.3	1.4	86.2	87.2	87.0	78.1	84.6
NEW SOUTH WALES[2]										
AusGrid	<0.1	<0.1	<0.1	<0.1	<0.1	81.1	79.7	82.6	81.8	46.7
Endeavour Energy	<0.1	<0.1	<0.1	<0.1	<0.1	96.2	92.0	90.2	87.0	80.1
Essential Energy	<0.1	<0.1	<0.1	<0.1	<0.1	61.4	51.4	62.5	57.5	55.8
ActewAGL	…	…	…	…	0.0	70.5	70.2	72.9	75.7	76.9
VICTORIA[3]										
Powercor	<0.1	<0.1	<0.1	<0.1	<0.1	90.0	86.6	85.3	67.4	70.2
SP AusNet	1.7	2.6	1.7	3.9	2.5	92.3	91.6	92.6	94.1	81.4
United Energy	0.1	0.1	0.0	0.2	1.8	73.0	73.1	76.2	60.1	61.5
CitiPower	<0.1	<0.1	<0.1	<0.1	<0.1	87.8	82.0	82.3	73.4	74.4
Jemena	0.8	0.9	0.1	<0.1	0.1	73.1	77.4	77.2	60.1	64.2
SOUTH AUSTRALIA[1]										
SA Power Networks	3.3	0.6	0.6	0.6	0.9	88.7	88.5	88.6	87.6	89.0
TASMANIA										
Aurora Energy	2.0	1.8	1.1	5.6	2.7	…	…	…	…	…

1. Completed connections data for Queensland and South Australia include new connections only.
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) and OTTER (Tasmania). 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 2011–12 related to the duration and frequency of supply interruptions exceeding specified limits. This outcome is consistent with previous years' results.

In Victoria in 2012, GSL payments rose slightly from the previous year, to over $8 million. A large increase in payments for low reliability in the SP AusNet network (from $3.9 million in 2011 to $6.6 million in 2012) was mostly offset by an improved reliability in the Powercor network (whose payments for low reliability fell from $3.5 million to $0.8 million). A rise in GSL payments also occurred in Queensland in 2011–12, largely due to diminished performance in the Ergon Energy network. Ergon Energy had increased instances of failing to adequately notify customers of supply interruptions and a longer average duration of unplanned supply interruptions.

SA Power Networks (South Australia) decreased GSL payments in 2011–12, to $2.6 million from $7.1 million in 2010–11. This fall was largely driven by a fall in payments for supply interruptions, with fewer severe weather events experienced over the year. Aurora Energy (Tasmania) also decreased its GSL payments in 2012–13, while payments by New South Wales networks were at a similar level to those of the previous year.