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2 ELECTRICTY NETWORKS

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

2.1 Electricity networks in the NEM

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

The NEM has 13 major electricity distribution networks (table 2.2). Queensland, New South Wales and Victoria each have multiple networks that are monopoly providers within designated areas. The ACT, South Australia and Tasmania each have one major network. Some jurisdictions also have small regional networks with separate ownership. The total length of distribution infrastructure in the NEM is around 750 000 kilometres—18 times longer than transmission infrastructure. Figure 2.1 illustrates the transmission and distribution networks in the NEM.

2.1.1 Ownership

Tables 2.1 and 2.2 list ownership arrangements for electricity networks in the NEM. The transmission networks in Victoria and South Australia, and three network 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. The ACT distribution network has joint government and private ownership. All networks (transmission and distribution) in Queensland, New South Wales and Tasmania are government owned.

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

- *Cheung Kong Infrastructure* and *Power Assets*, which jointly have a 51 per cent stake in two Victorian distribution networks (Powercor and CitiPower) and a 200 year lease of the South Australian distribution network (SA Power Networks, formerly ETSA Utilities). The remaining 49 per cent in 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*, which owns the Jemena distribution network and has minority ownership of the United Energy distribution network, both in Victoria. It has a 50 per cent share in the ACT distribution network (ActewAGL) and a 51 per cent stake in SP AusNet, which owns the Victorian transmission network and SP AusNet distribution network.

These businesses also own or have equity in a number of gas networks (chapter 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 Tasmania and the ACT,[1] common ownership occurs in electricity distribution and retailing, with ring fencing arrangements for operational separation.
- The Tasmanian Government announced industry reforms in 2012 that will separate the ownership of energy networks from energy retailing. It will also merge the transmission (Transend) and distribution (Aurora Energy) networks.
- 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.

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).

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	4 720	6 260	2 455	1 July 2012–30 June 2017	Queensland Government
TransGrid	NSW	13 957	70 828	13 760	3 880	4 485	2 620	1 July 2009–30 June 2014	New South Wales Government
SP AusNet	Vic	6553	52 352	9 982	2 940	2 365	830	1 Apr 2008–30 Mar 2014	Publicly listed company (Singapore Power International 51%)
ElectraNet	SA	5 591	13 045	3 570	1 365	1 415	840	1 July 2008–30 June 2013	Powerlink (Queensland Government), YTL Power Investments, Hastings Utilities Trust, UniSuper
Transend	Tas	3 688	11 185	1 377	1 010	1 010	645	1 July 2009–30June 2014	Tasmanian Government
NEM TOTALS		43 775	194 751		13 915	15 535	7 390		
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		130		1 Oct 2003–30 June 2013	Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)
Basslink	Vic–Tas	375				910		Unregulated	Publicly listed CitySpring Infrastructure Trust (Temesek Holdings (Singapore) 37%)

GWh, gigawatt hours; MW, megawatts.

1. Revenue and investment data are forecasts over the current regulatory period, converted to June 2011 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 2011 dollars.
3. Not all interconnectors are listed. The unlisted interconnectors, which form part of the state based networks, are Heywood (Victoria – South Australia), QNI (Queensland – New South Wales) and New South Wales – Victoria.
4. Basslink is not regulated, so has no regulated asset base. The listed asset value is the estimated construction cost.

Sources: AER, *Transmission network service providers: electricity performance report for 2010–11*, 2012 regulatory determinations by the AER.

Table 2.2 Electricity distribution networks

NETWORK	CUSTOMER NUMBERS	LINE LENGTH (KM)	MAXIMUM DEMAND (MW), 2010–11	REVENUE—CURRENT PERIOD ($ MILLION)[1]	ASSET BASE ($ MILLION)[2]	INVESTMENT—CURRENT PERIOD ($ MILLION)[1,3]	CURRENT REGULATORY PERIOD	OWNER
QUEENSLAND								
Energex	1 316 295	53 928	4 875	6 900	8 120	5 970	1 Jul 2010–30 Jun 2015	Qld Government
Ergon Energy	689 277	160 998	2 429	6 425	7 380	5 275	1 Jul 2010–30 Jun 2015	Qld Government
NEW SOUTH WALES AND ACT								
AusGrid[4]	1 619 988	49 781	5 812	9 300	8 965	8 855	1 Jul 2009–30 Jun 2014	NSW Government
Endeavour Energy	877 340	34 172	4 069	4 680	3 925	3 150	1 Jul 2009–30 Jun 2014	NSW Government
Essential Energy	1 301 626	190 531	2 292	5 920	4 595	4 415	1 Jul 2009–30 Jun 2014	NSW Government
ActewAGL	168 937	4 922	701	770	635	325	1 Jul 2009–30 Jun 2014	ACTEW Corporation (ACT Government) 50%; Jemena (Singapore Power International) 50%
VICTORIA								
Powercor	723 094	84 791	2 351	2 570	2 260	1 600	1 Jan 2011–31 Dec 2015	Cheung Kong Infrastructure/ Power Assets 51%; Spark Infrastructure 49%
SP AusNet	637 810	48 841	1 798	2 475	2 120	1 510	1 Jan 2011–31 Dec 2015	SP AusNet (listed company; Singapore Power International 51%)
United Energy	641 130	12 875	1 962	1 700	1 410	905	1 Jan 2011–31 Dec 2015	DUET Group 66%; Jemena (Singapore Power International) 34%
CitiPower	311 590	7 406	1 453	1 240	1 315	850	1 Jan 2011–31 Dec 2015	Cheung Kong Infrastructure/ Power Assets 51%; Spark Infrastructure 49%
Jemena	314 734	6 043	1 008	985	770	485	1 Jan 2011–31 Dec 2015	Jemena (Singapore Power International)
SOUTH AUSTRALIA								
SA Power Networks[5]	825 218	87 226	3 128	3 620	2 860	2 225	1 Jul 2010–30 Jun 2015	Cheung Kong Infrastructure/ Power Assets 51%; Spark Infrastructure 49%
TASMANIA								
Aurora Energy	275 536	25 844	1 760	1 290	1 410	555	1 Jul 2012–30 Jun 2017	Tas Government
NEM TOTALS	9 702 575	767 358		47 875	45 765	36 120		

MW, megawatts.

1. Revenue and investment data are forecasts over the current regulatory period, converted to June 2011 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 2011 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. ETSA Utilities was rebranded as SA Power Networks in 2012.

Sources: Regulatory determinations and performance reports by the AER and OTTER (Tasmania).

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 must assess the forecasts submitted by a network business of the revenue it 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.

The largest component is the return on capital, which may account for up to two-thirds of revenues. The size of a network's RAB (and projected investment) and its weighted average cost of capital (the rate of return necessary to cover a commercial return on equity and efficient debt costs) 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 must determine 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 revenues *or prices* that can be earned or charged during a period. The available mechanisms in distribution include:

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

Until November 2012, the regulatory process for transmission businesses began 13 months before the end of the current regulatory period and took 11 months to complete. The AER must publish a final decision on a proposal at least two months before the beginning of the next regulatory period. The process for distribution businesses commenced earlier—24 months before the end of the current regulatory period—to allow time for preliminary consultation on the framework and approach for a determination. A Rule change in November 2012 provided for the regulatory process to be extended by four months to allow more effective consultation with stakeholders (section 2.2.2).

2.2.2 Refining the regulatory process and approach

In 2011 the AER submitted Rule change proposals to the Australian Energy Market Commission (AEMC), seeking changes in chapters 6 and 6A of the Rules to better promote efficient investment in, and use of, energy services for the long term interests of consumers. Following detailed consultation, the AEMC released Rule changes in November 2012 that will strengthen the AER's capacity to set network price increases so consumers do not pay more than necessary for a reliable energy supply. The changes:

- create a common approach to setting the *cost of capital* across electricity and gas network businesses, whereby the AER makes a best possible estimate of a rate of return for a benchmark efficient service provider at the time of making a regulatory determination. The AER will undertake public consultation at least every three years to develop its approach to setting the rate of return, completing the first review by November 2013.
- enhance *incentives for efficient investment* by equipping the AER with new regulatory tools, such as a review of the capital expenditure undertaken by a network business to ensure it is prudent and efficient; expenditure in excess of regulatory approvals may be removed from the RAB if the AER finds it is not prudent or efficient.
- clarify the AER's powers to assess and amend *capital and operating expenditure proposals* by network businesses. Additionally, the AER will publish annual benchmarking reports on the relative efficiency of the businesses.
- commence the electricity regulatory process four months earlier to allow more effective consultation with stakeholders. More information will be made available early in the regulatory process to strengthen consumer engagement. The framework and approach process will extend to transmission businesses and the AER will publish an issues paper after a regulatory proposal is submitted to it.

In addition to the Rule change proposals, the AER is continuing to strengthen its regulatory approach under the current Rules framework by refining:

- benchmarking techniques and tools and their application in regulatory decisions. The AER is developing key benchmarking indicators in consultation with industry, with a view to applying enhanced metrics in regulatory reviews of the New South Wales and ACT electricity distribution networks.
- information requirements on energy business, to improve the quality and consistency of data for regulatory reviews and annual performance reporting. The enhancements also aim to improve the robustness of regulatory decision making, and provide important data for developing and applying benchmarking techniques.

2.2.3 Regulatory timelines and recent AER activity

Figure 2.2 shows the regulatory timelines for electricity networks in each jurisdiction. In 2012 the AER:

- published final determinations for Aurora Energy (Tasmanian electricity distribution) and Powerlink (Queensland electricity transmission)
- began reviews of ElectraNet (South Australian electricity transmission) and Murraylink (transmission interconnector between Victoria and South Australia) for the regulatory periods commencing 1 July 2013, and released draft determinations in November 2012
- began preparatory work for reviews of the New South Wales and ACT electricity distribution businesses for the regulatory periods commencing 1 July 2014. The November 2012 Rule change on regulatory process includes transitional arrangements for these jurisdictions, which will affect the AER's process and timing for the reviews.

In addition to revenue determinations, the AER undertakes other functions associated with economic regulation. It assesses network proposals on matters including cost pass-throughs and contingent projects; develops and applies service incentive regimes and ring fencing policies and other regulatory guidelines; assists in access and connection disputes; and undertakes annual tariff reviews for distribution businesses. The AER monitors the compliance of network businesses with the Electricity Rules, and reports on outcomes, including in quarterly compliance reports.[2]

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.

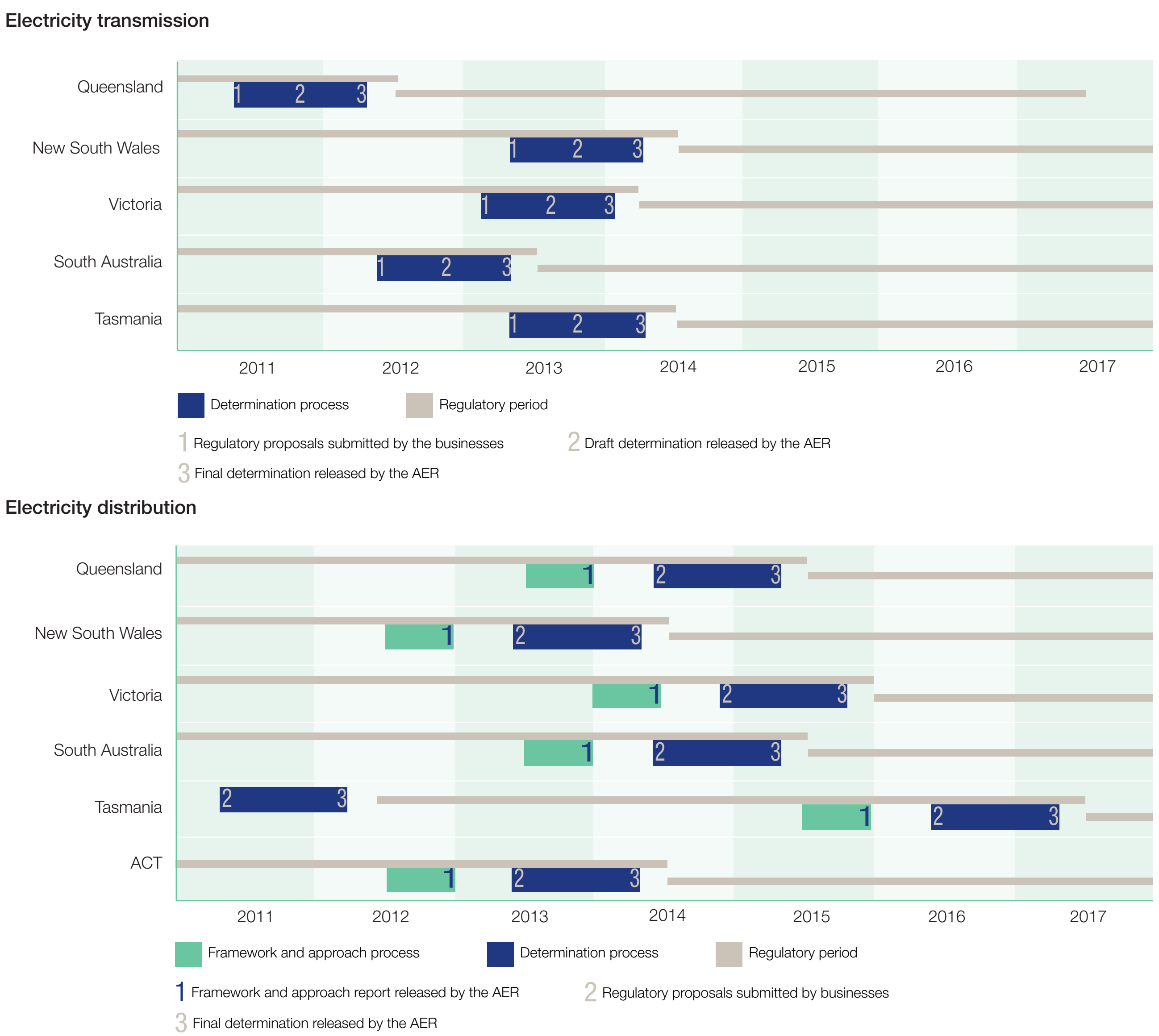
Between June 2008 and June 2012 network businesses sought review of 17 AER determinations on electricity networks—three reviews in transmission and 14 in distribution.[3] The Tribunal's decisions increased allowable electricity network revenues by around $3.2 billion, with substantial impacts on retail 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—the subject of review applications for eight networks, with a combined revenue impact of over $900 million.

2 AER, *Strategic plan and work program 2012–13*.

3 Three 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* (Cth).

Figure 2.2
Indicative timelines for AER determinations on electricity networks



Note: For reviews commencing from 2013, Rule changes made by the AEMC in November 2012 will lengthen the regulatory process to commence four months earlier than the dates set out above. Transitional arrangements arising from the Rule changes may affect these timelines.
Source: AER.

In January 2012 the Tribunal made decisions on matters appealed by the Victorian electricity distribution networks (following the AER's determination of October 2010). The matters on which the businesses sought review varied. All sought review of gamma and the debt risk premium that is applied to calculate the cost of capital. Other matters included aspects of approved capital and operating expenditure, the method of escalating the RAB over the regulatory period, and the application of pass through provisions.

The Tribunal upheld aspects of the AER's decisions (relating to the treatment of pass throughs and some operating expenditure), but overturned the AER's approach to certain operating costs and the debt risk premium, indexation of the RAB, and the application of penalties from two incentive schemes under the previous regulatory regime. Some matters were remitted to the AER for a further decision. These Tribunal decisions increased the Victorian networks' allowable revenues by around $255 million (a 3 per cent increase) over five years. This increase represents a 0.5–1.5 per cent rise in a typical residential electricity bill.

In April 2012 the Tribunal completed a review of the AER's determination on smart meter costs for Victoria's SP AusNet network. The AER found SP AusNet should have reconsidered its decision to use WiMAX communications technology (rather than the cheaper mesh radio technology adopted by the other distribution businesses) and removed associated expenditure from its budget. The Tribunal remitted that aspect of the determination back to the AER. Additionally, it required the AER to allow certain costs in respect of foreign exchange contracts and project management labour. The AER expected to release an amended determination in December 2012. SP AusNet also sought judicial review of the AER's determination. The Federal Court adjourned a decision on this application in April 2012.

At October 2012 no electricity matters were before the Tribunal. Aurora Energy (Tasmanian distribution) and Powerlink (Queensland transmission) did not seek review of the AER's decisions made in April 2012 on these networks for the period commencing 1 July 2012.

2.2.5 Independent review of merits review arrangements

In 2012 the Standing Council on Energy and Resources (SCER) commissioned an independent review of the operation of the *limited merits review regime*. In its final report, released in September 2012, the review panel found the regime has not operated as intended. In particular, the regime:

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

The panel found a limited merits review regime is preferable to the alternatives—such as *de novo* (full) review or reliance on judicial review only—but recommended the following improvements:

- reviews should be conducted by a new administrative body attached to the AEMC
- the regime should be limited to a single ground of appeal—that a materially preferable decision exists—and should assess review matters in relation to the national energy objectives
- a review should be investigative rather than adversarial, with greater input from consumers. Additionally, the AER's role in assisting the review body should be clarified in the Electricity Law.
- the review body should be free to explore any aspect of a decision that it considers relevant.

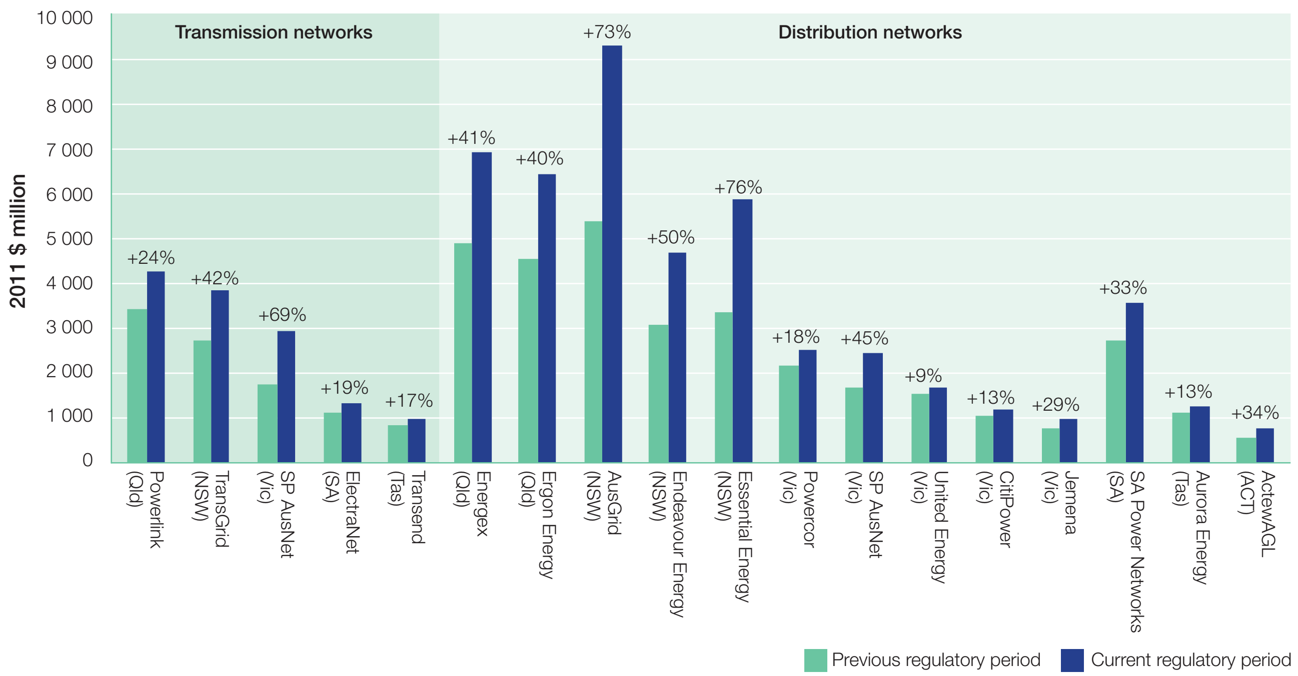
The Council of Australian Governments (CoAG) considered the panel's recommendations in December 2012 (see *Market overview*, section A.3.2).

2.3 Electricity network revenues

Figure 2.3 illustrates AER revenue allowances for electricity networks in the current five year regulatory periods compared with previous periods. Combined network revenues were forecast at $60 billion over the current cycle, comprising over $12 billion for transmission and $47 billion for distribution—a 44 per cent real increase from the previous regulatory periods. The main drivers are higher capital expenditure (investment), and increased capital financing and operating costs (discussed in sections 2.4 and 2.5).

The forecast cost of capital used to determine revenue allowances in the current regulatory periods were higher for most network business than in previous periods. The increases led to average revenue forecasts increasing by 7 per cent more than if the cost of capital were unchanged.

Figure 2.3
Electricity network revenues



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: Regulatory determinations by the AER.

The cost of capital comprises several parameters. The primary factor underpinning the increases is the 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 in 2012 reflect recent reductions in the risk free rate and market and debt risk premiums that have lowered the overall cost of capital.

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

2.4 Electricity network investment

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

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

2.4.1 Regulatory test, RIT-T and RIT-D

The regulatory process approves the overall efficiency of a business's capital expenditure program. Additionally, there is a separate assessment process 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 requires a business to determine whether a proposed augmentation passes a cost–benefit analysis or provides a least cost solution to meet network reliability standards.[4]

The regulatory investment test for transmission (*RIT-T*), introduced in August 2010, requires a more comprehensive assessment and applies to a wider range of projects than the previous test. The RIT-T also prescribes more closely the market benefits and costs that an assessment may consider.

Under the RIT-T, a network business must identify the purpose of an investment as well as all credible options for achieving that purpose. It must publicly consult on its proposal. Affected parties can lodge a formal dispute.

The AER developed the RIT-T and the previous regulatory test. Additionally, it:

- helps resolve disputes over how the tests are applied
- monitors and enforces compliance. The AER conducted a number of compliance reviews in 2012
- periodically reviews project cost thresholds. The AER initiated the first cost thresholds review for the RIT-T in July 2012.

For distribution networks, the regulatory test still applies. But the AEMC in October 2012 finalised a Rule change to introduce a RIT-D similar to the RIT-T.[5] The AER must develop and publish the RIT-D (and related application guidelines) by September 2013. The RIT-D will apply to investment projects over $5 million. It includes a dispute resolution process, and requires distribution businesses to release annual planning reports and maintain a demand side engagement strategy (section 2.9.5).

A number of RIT-T and regulatory test processes were occurring in 2012, including for the following projects:

- ElectraNet and AEMO (as the transmission network planner in Victoria) were assessing the viability of upgrading the Heywood interconnector between Victoria and South Australia. A draft report in September 2012 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.
- Powerlink and TransGrid were evaluating an upgrade to the transfer capacity of the Queensland–New South Wales interconnector (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.
- AEMO identified forecast demand growth in Victoria requires greater supply capability in eastern Melbourne, and in regional Victoria around Bendigo and Ballarat. The analysis considered network options, as well as demand management.
- AEMO, Jemena and Powercor identified emerging transmission limitations in western Melbourne from the expansion of residential, industrial and commercial load. They forecast extra capacity would be required by 2016–17, and chose the establishment of a new terminal station at Deer Park as the preferred option.
- ElectraNet was seeking to reinforce the transmission network in the Lower Eyre Peninsula to meet reliability standards and prepare for additional loads in the area from 2014.
- Powerlink and Energex identified forecast demand growth around southern Brisbane from summer 2013–14 would require additional network capacity to meet reliability obligations. They identified five network augmentation options for analysis.

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

5 AEMC, National Electricity Amendment (Distribution Network Planning and Expansion Framework) Rule 2012.

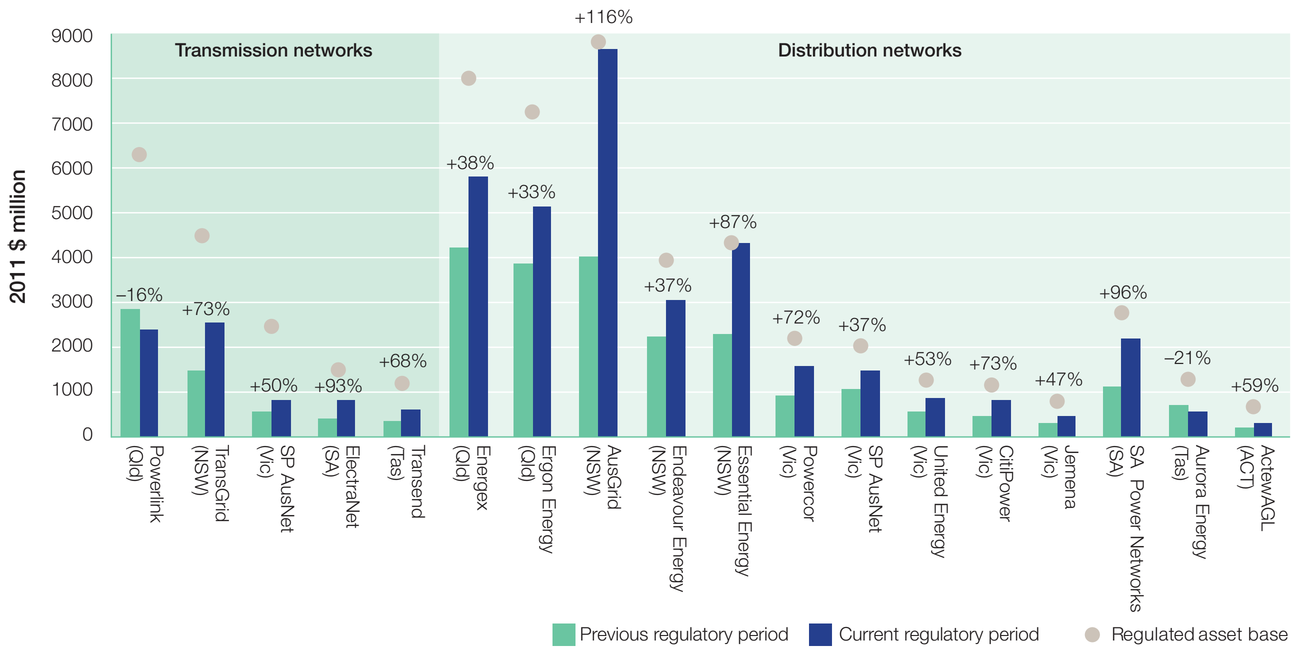
2.4.2 Investment trends

Figure 2.4 illustrates investment allowances for electricity networks in the current five year regulatory periods compared with previous periods. It shows the RAB for each network as a scale reference. 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 27 per cent in transmission and 60 per cent in distribution (in real terms). More recent determinations reflect a different 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

Figure 2.4
Electricity network investment



Notes:

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

Investment data reflect forecast capital expenditure for the current regulatory period (typically, five years), 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.

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

Sources: Regulatory determinations by the AER.

new bushfire (safety) standards, and respond to forecasts made at the time of rising peak demand.

More recent determinations, however, reflect a moderation in forecast growth in industrial and residential energy use, including peak demand (section 1.1). This led to a revision in forecast investment requirements for the networks reviewed in 2012. The AER found:

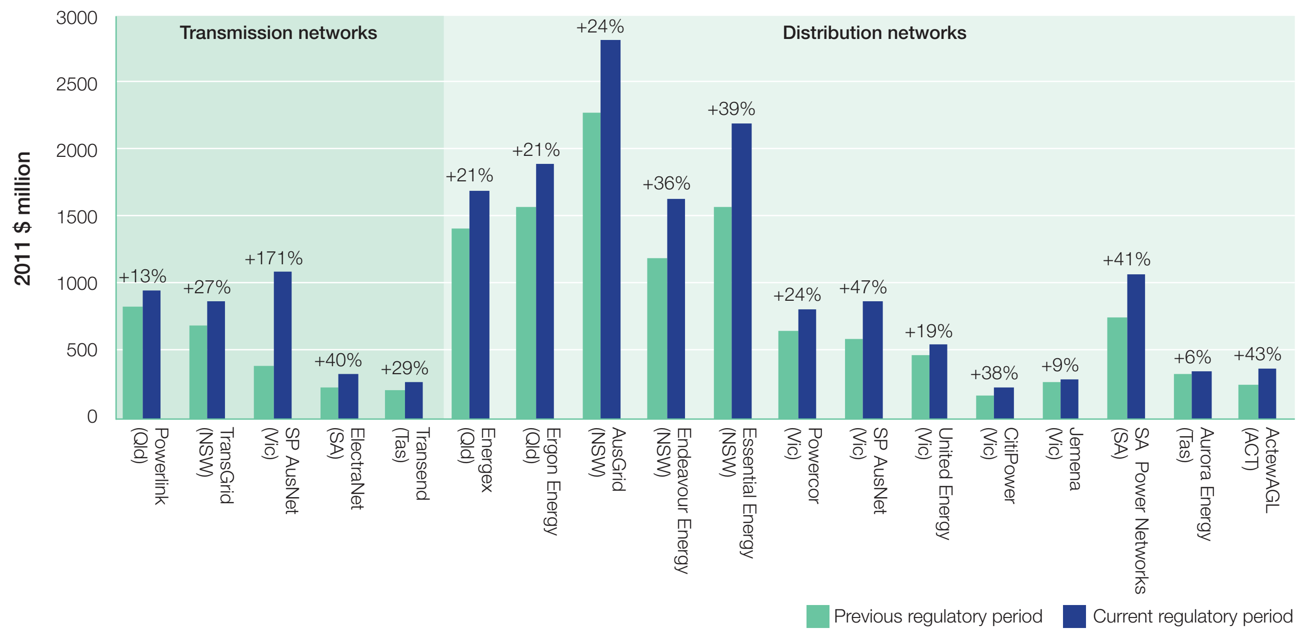
- a softening in forecast peak demand growth in Queensland meant Powerlink's transmission investment requirements were 16 per cent less than in the previous regulatory period
- subdued economic growth in Tasmania, with lower expected demand and fewer new connections, meant Aurora Energy's investment requirements were 21 per cent less than in the previous regulatory period.

2.5 Operating and maintenance expenditure

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

Figure 2.5 illustrates operating and maintenance expenditure allowances for electricity networks in the current five year regulatory periods compared with previous periods. In the current cycle, transmission businesses in the NEM are forecast to spend $3.5 billion on operating and maintenance costs. Distribution businesses are forecast to spend almost $15 billion.

Figure 2.5
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 period.

Sources: Regulatory determinations by the AER.

Differences in the networks' operating environments result in significant variations in expenditure allowances. On average, costs are forecast to rise by 48 per cent in transmission and 28 per cent in distribution over the current regulatory periods. More recent determinations reflect lower rates of growth in line with flatter forecasts of energy demand and input costs.

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, largely stemming from government decisions following the 2009 Victorian bushfires.

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. 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 as solutions to 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

CoAG in December 2012 approved the adoption in principle of the full set of *Power of choice* recommendations.

2.6.2 Metering and smart grids

The rollout of interval meters—with time based data on energy use and communication capabilities for remote reading and customer connection to the network—is central to many of the AEMC's *Power of choice* recommendations. This type of metering, when coupled with time varying prices can encourage customers to actively manage their electricity use. In the longer term, it may facilitate dynamic grid operation.

The *Power of choice* review recommended that all new meters installed for residential and small businesses consumers be interval meters with remote communication capacity. It proposed that new metering be installed on an accelerated basis for large residential and small business consumers. The AEMC prefers that the supply of metering and related data services be contestable, with retailers having primary responsibility.

Under the AEMC proposal, a network business would be required to implement time varying pricing in network charges, to encourage retailers to reflect these charges in customer contracts. It would remain open to small and medium sized customers to choose between time varying and flat network charges. CoAG in December 2012 proposed the phasing in of time varying network charges by July 2014.

The Victorian Government expects to complete a rollout of interval meters with remote communications to all customers by the end of 2013. A moratorium on the introduction of time varying prices for small customers with interval meters is in place until July 2013.[6] From that time, customers will be able to choose to move to time varying prices.

Interval meter costs have been progressively passed on to Victorian retail customers since 1 January 2010. Network charges increased by almost $70 for a typical small retail customer in 2010, with a further increase of around $8 in 2011. In October 2011 the AER released a final determination on metering services budgets and charges for 2012–15.[7] Over this period, meter costs will increase network charges for a typical small retail customer by $9–21 per year.[8]

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

6 If the customer consumes less than 20 megawatt hours of electricity per year.

7 AER, *Victorian advanced metering infrastructure review—2009–11 AMI budget and charges applications, final determination*, 2009.

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

2.6.3 Other demand management initiatives

In distribution, the AER applies incentives for demand management that enable businesses to investigate and implement non-network approaches to manage demand. The schemes fund innovative projects that are additional to the demand management 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. No business is compelled to take up the scheme. In reviewing the impact of climate change policies on energy market frameworks, the AEMC recommended expanding the allowance to cover innovations in connecting generators to distribution networks. A Rule change on this issue was finalised in December 2011. The AER will review the demand management incentive schemes once CoAG finalises its response to the AEMC's *Power of choice* recommendations.

In April 2012 ClimateWorks Australia, Seed Advisory and the Property Council of Australia submitted a Rule change request to the AEMC on the process for connecting generators to the distribution network. The request sought to enable a more timely, clear and less expensive process for these connections. The proponents considered the current process poses uncertainty for connection applicants. The AEMC published a consultation paper in August 2012 on the proposal.

The Senate Select Committee on electricity prices (section 2.9.1) recommended in November 2012 that SCER examine barriers to embedded generation. Additionally, it recommended that the AEMC amend the Electricity Rules to ensure network charges and payments (for network support) for these generators are appropriate.

2.7 Transmission network performance

Barometers of performance for electricity transmission networks include:

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

2.7.1 Reliability of supply

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 2010–11 caused less than 3 minutes of unsupplied energy in New South Wales, Victoria and South Australia; Tasmania had 8 minutes of unsupplied energy. No data were published for Queensland. Performance improved in 2010–11 compared with the previous year in Victoria, South Australia and Tasmania.[9]

State and territory agencies determine transmission reliability standards. The AEMC in 2008 and 2010 recommended a national framework be introduced for a more consistent approach. The framework would economically derive standards using a customer value of reliability or a similar measure. A body independent of transmission network owners would determine standards by jurisdiction. A national reference template would provide a basis for comparing the standards in each jurisdiction, and jurisdictions would need to justify any divergence from the template.

The SCER in November 2011 agreed with the AEMC's recommendations, noting the reforms would help optimise the balance between investment in transmission and generation assets. The reforms would also assist the AER's revenue determination process and enhance the effectiveness of the RIT-T.[10] The SCER requested the AEMC develop an implementation program for the reforms.

In its *Transmission frameworks review* (section 2.9.2), the AEMC noted national consistency in reliability standards would complement its proposals to coordinate decision making in transmission investment. It identified a role for AEMO, as the national transmission planner, to provide independent advice to the institutions that set reliability standards in each jurisdiction. Submissions to the AEMC review largely supported the proposal for a national framework on reliability standards.

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 lead to network congestion, especially at times of high demand. Some congestion results from factors within the control of a

9 ESAA, *Electricity gas Australia 2012*, 2012.

10 MCE, *Transmission reliability standards review*, Response to AEMC final report, 2011.

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.

If a major transmission outage occurs in combination with other generation or demand events, it can interrupt the supply of energy to some customers. This scenario is, however, 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 1.4).

Not all congestion is inefficient. Reducing congestion may require significant investment to augment the transmission network. Eliminating congestion is efficient 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.

2.7.3 Service target performance incentive scheme—transmission

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

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

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

The scheme includes a separate component based on the market impact of transmission congestion (box 2.1). Under this component, a business can earn up to a further 2 per cent of its regulated revenue.

The results are standardised for each network to derive an 's factor' that can range between –1 (the maximum penalty) and +3 (the maximum bonus). Table 2.3 sets out the s factors for each network for the past six years. While performance against individual component targets has varied, the networks generally receive financial bonuses for overall performance. The only businesses to receive financial penalties in 2011 were TransGrid and Directlink.

In 2010–11 underperformance was evident in some areas. In New South Wales, transmission circuit availability was below target. Queensland and Tasmania underperformed in terms of critical transmission circuit availability. In Tasmania and Victoria, the average duration of outages increased.

Following a review, the AER in September 2012 released a draft proposal to amend the incentive scheme:

- Under the *service component*, a transmission circuit availability parameter would be replaced. Also, the definitions for other parameters would be standardised across the businesses. A 'near miss' parameter should be introduced (but with no financial incentive or penalty) that measures the number of times that protection and control equipment fail to operate correctly.
- Under the *market impact component*, a network's performance would be assessed as an average over two calendar years, and the target would be based on outcomes over the previous three calendar years, to encourage consistency in network performance.
- A *network capability component* would be introduced to incentivise transmission businesses to undertake expenditure to improve network capability. A business would receive an allowance to undertake a set of approved projects, and would be subject to penalties if it failed to achieve its target. AEMO would play a part in prioritising the projects to deliver best value for money for consumers.

The AER expected to finalise the amendments in December 2012. The changes, if adopted, would first apply to SP AusNet, Transend and TransGrid from 2014, although transitional arrangements associated with proposed changes to chapter 6A of the Electricity Rules will see a staged approach to adopting the new scheme.

Table 2.3 S factor values

	2006	2007	2008		2009		2010	2011
Powerlink		0.82		0.53		0.17	2.62	2.37
TransGrid	0.63	0.17		0.31	0.22	0.06	1.21	1.25
AusGrid	0.39	–0.14		0.72		0.37		
SP AusNet	–0.29	0.06	0.15	0.82		0.51	0.58	0.72
ElectraNet	0.59	0.28	0.29	–0.40		0.60	0.00	0.84
Transend	0.06	0.56		0.85	0.88	0.11	0.35	–0.41
Directlink	–0.54	–0.62		–1.00		–0.98	–1.00	–0.87
Murraylink	0.21	–0.32		0.69		0.87	1.00	0.70

Notes:

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

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

TransGrid and Transend reported separately for the first and second halves of 2009. AusGrid data for 2009 are for the six months to June; AusGrid moved to the distribution performance framework on 1 July 2009.

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

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

Box 2.1 Incentives to reduce network congestion

The AER in 2008 expanded the *service target performance incentive scheme* to provide incentives for network businesses to apply relatively low cost solutions to congestion. The *market impact parameter* operates as a bonus only scheme and rewards transmission network owners for improving their operating practices to reduce congestion. These practices may include more efficient outage timing and notification, the minimising of outage impact on network flows (for example, by conducting live line work, maximising line ratings and reconfiguring the network) and equipment monitoring.

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

TransGrid, Powerlink, ElectraNet and SP AusNet participate in the scheme, which appears to be driving improved behaviour by the transmission businesses. The AER's qualitative analysis of market outcomes found a reduction in outage related high price events across all regions that participate in the scheme. Payments to date under the scheme total around $46 million (table 2.4).

Table 2.4 Incentive payments under the market impact parameter

	PAYMENTS ($M)			
TRANSMISSION NETWORK	2009	2010	2011	TOTAL
TransGrid	1.3[1]	10.3	10.7	22.3
Powerlink		6.8[1]	15.2	22.0
SP AusNet			0.0[2]	0.0
ElectraNet			1.5	1.5

1. Payments for 1 July to 31 December.
2. Payments for 1 August to 31 December.

2.8 Distribution network performance

Barometers of performance for electricity distribution networks include:

- reliability of supply
- levels of customer service.

2.8.1 Reliability of distribution networks

Reliability is the main barometer of service 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 in high levels of redundancy (spare capacity) to improve reliability. In addition, the impact of a distribution outage tends to be localised to part of the network, compared with the potentially widespread impact of a generation or transmission outage. For these reasons, network outages should be kept to efficient levels—based on the assessed value of reliability to the community (measuring the impact on services) 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 and affect customer bills. The SCER in August 2011 noted the significant impact of distribution investment on retail electricity prices, and directed the AEMC to review the approaches to setting distribution reliability standards across jurisdictions, with a view to developing a national approach. This review follows the AEMC review of transmission reliability standards, completed in 2010 (section 2.7.1).

In November 2012 the AEMC proposed the introduction of a nationally consistent framework for distribution reliability.[11] It recommended jurisdictions continue to set reliability standards, but follow a consistent national approach based on output performance. It also recommended reporting and incentive scheme arrangements be standardised.

In parallel with this broad review of distribution reliability standards, the SCER also directed the AEMC to make a more detailed review of standards in New South Wales. The aim was to identify the costs and benefits of alternative approaches. The AEMC's August 2012 report found a reduction in reliability standards could reduce distribution network investment by $275 million to $1.3 billion over 15 years, depending on how much the standards are reduced. It forecast an increase in outages for an average customer of 2–15 minutes per year, corresponding with average customer savings of $3–15 per year. The cost savings in reducing reliability standards from their current settings were found to provide consumer benefits that would exceed the adverse impact of weaker reliability performance. In contrast, the costs of further improving reliability would outweigh the benefits.[12]

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 2.6 estimates historical data on the average duration (SAIDI) and frequency (SAIFI) of outages experienced by distribution customers. The data include outages that originate in the generation and transmission sectors.

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

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

11 AEMC, *Review of distribution reliability outcomes and standards, draft report—national workstream*, 2012.

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

Figure 2.6
System reliability

SAIDI

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

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

In 2010–11 the average duration of outages per customer rose in all jurisdictions other than Tasmania. The largest increase occurred in Queensland, where an average customer experienced 1122 minutes of outages in that year—the highest duration in a NEM jurisdiction in the past decade. Performance on both the Energex and Ergon Energy networks was affected by extreme weather, with severe flooding in the south east and Cyclone Yasi in the north. 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.

South Australian customers also experienced a large increase in outage duration in 2010–11, with a higher than average level of extreme weather events during the period—including three severe storms that accounted for one-third of the outage time. Tasmanian outages in 2010–11 were close to the state's average for the past 10 years. This performance followed a high average outage duration in 2009–10, largely caused by six days when storms, lightning and wind affected network performance.

The SAIFI data show the average frequency of outages was relatively stable between 2002–03 and 2010–11, with energy customers across the NEM experiencing an outage around twice a year. The average frequency of outages in 2010–11 was consistent with that of the previous year in all jurisdictions except South Australia (which had an increase in the number of outages).

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* of outages for each distribution business. The targets are based on historical data. From a customer perspective, the unadjusted reliability data in figure 2.6 are relevant, but in assessing network performance the AER normalises data to exclude interruption sources beyond the network's reasonable control. In 2010–11 most businesses underperformed against their targets—that is, their customers experienced more minutes of outages than targeted.

The AER also sets targets for the average *frequency* of outages for some distribution businesses. In 2010–11 all businesses outperformed their targets—that is, their customers experienced less frequent outages than targeted.

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 data. Customer service outcomes in 2010–11 broadly aligned with those of previous years, but there was some deterioration in performance. Aurora Energy (Tasmania) and SP AusNet (Victoria) recorded their highest proportion of late connections for the past five years. And call centre responsiveness fell sharply in four of the Victorian networks and Queensland's Ergon Energy network.

2.8.3 Distribution service performance incentives

The AER's service target performance incentive scheme encourages distribution businesses to maintain or improve service performance. It focuses on supply reliability (section 2.8.1) and customer service (section 2.8.2). It includes a guaranteed service level (GSL) component, under which customers are paid directly if performance falls below threshold levels. The GSL component does not apply if the distribution business is subject to jurisdictional GSL obligations.

The incentive scheme generally provides financial bonuses and penalties of up to 5 per cent of revenue to network businesses that meet (or fail to meet) performance targets.[13] 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 currently 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 in a network. A fire start includes any fire that originates from a network, or is caused by something coming into contact with the network. This 'f factor' scheme will reward or penalise the businesses $25 000 per fire under or over their fire start targets.

13 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				
	2006–07	2007–08	2008–09	2009–10	2010–11	2006–07	2007–08	2008–09	2009–10	2010–11
QUEENSLAND[1]										
Energex	0.6	10.8	2.5	0.4	…	79.1	96.3	89.7	90.0	86.6
Ergon Energy	0.5	0.7	0.3	0.4	…	87.0	86.2	87.2	87.0	78.1
NEW SOUTH WALES[2]										
AusGrid	<0.1	<0.1	<0.1	<0.1	<0.1	74.3	81.1	79.7	82.6	83.6
Endeavour Energy	<0.1	<0.1	<0.1	<0.1	<0.1	70.9	96.2	92.0	90.2	90.2
Essential Energy	<0.1	<0.1	<0.1	<0.1	<0.1	…	61.4	51.4	62.5	61.1
ActewAGL	…	…	…	…	…	62.4	70.5	70.2	72.9	75.7
VICTORIA[3]										
Powercor	<0.1	<0.1	<0.1	<0.1	<0.1	89.4	90.0	86.6	85.3	67.4
SP AusNet	2.7	1.7	2.6	1.7	3.9	91.2	92.3	91.6	92.6	94.1
United Energy	0.1	0.1	0.1	0.0	0.2	74.0	73.0	73.1	76.2	60.1
CitiPower	0.1	<0.1	<0.1	<0.1	<0.1	87.2	87.8	82.0	82.3	73.4
Jemena	0.2	0.8	0.9	0.1	<0.1	79.9	73.1	77.4	77.2	60.1
SOUTH AUSTRALIA[1]										
SA Power Networks	0.5	3.3	0.6	0.6	0.6	89.3	88.7	88.5	88.6	87.6
TASMANIA[1]										
Aurora Energy	3.9	4.6	4.6	3.7	14.5	…	…	…	…	…

1. Completed connections data for Queensland, South Australia and Tasmania include new connections only. Queensland data for 2009–10 are for the year ended 31 March 2010.
2. New South Wales completed connections data are state averages.
3. Victorian data are for the calendar year beginning in that period.

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

Jurisdictional GSL schemes

Jurisdictional GSL schemes provide for payments to customers experiencing poor service. The schemes are not intended to provide legal compensation to customers, but to enhance the service performance of distribution businesses.

These schemes 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 2011) and New South Wales (in 2010–11), GSL payments rose slightly from the previous year. Payments in Victoria (almost $8 million, compared with $7 million in 2010) were mostly for low reliability in the Powercor and SP AusNet networks. The rise in payments by New South Wales networks was largely due to a slightly diminished performance in providing timely and accurate information on interruptions to supply.

SA Power Networks (South Australia) also increased GSL payments in 2010–11, to almost $7 million—nearly four times higher than its payment in 2009–10. This rise was largely driven by an increase in payments for supply interruptions longer than 18 hours, resulting from severe weather events.

Aurora Energy (Tasmania) made GSL payments of $1.1 million in 2010–11. This total was significantly down on payments in 2009–10 ($4.7 million) resulting from outages associated with a major storm in September 2009.

2.9 Policy developments for electricity networks

The AEMC undertakes reviews on its own initiative or as directed by the SCER, and provides policy advice on electricity market issues. It is also responsible for Rule making under the Electricity Law, including determinations on proposed Rule changes. It progressed or finalised a number of reviews and Rule change proposals in 2012.

2.9.1 Senate Select Committee on electricity prices

In August 2012 a Senate Select Committee was formed to investigate the cause of electricity price rises, review the regulatory framework for electricity networks, and identify options to manage energy use and reduce energy costs.

The committee released its final report in November 2012. Many of its recommendations were proposed in previous reviews, including the AEMC's review of the Rules for network regulation (section 2.2.2), the independent review of the Limited merits review regime (section 2.2.4), the Transmission frameworks review (section 2.9.2) and the *Power of choice* review (section 2.6.1). The committee recommended:

- developing new guidelines for calculating a network business's required rate of return
- having the AEMC set national reliability standards that reflect customers' valuation of reliability
- making AEMO the single network planning agency for the NEM, including responsibility for implementing reliability standards
- decoupling network revenues from energy volumes, and providing more guidance in the Electricity Rules on setting network prices to reflect costs
- enabling the AER to review the efficiency of historical capital expenditure
- providing incentives for generators to consider the network costs of their location decisions, and for more transparent negotiation between generators and network businesses.

2.9.2 Transmission frameworks review

The AEMC in 2012 continued reviewing arrangements for the provision and use of electricity transmission services, and implications for the NEM's market frameworks. The review aims to ensure market frameworks—including incentives for generation and network investment—align with frameworks for network operation to deliver efficient outcomes. It stems from earlier AEMC findings that climate change policies would affect the use of transmission networks and place stress on market frameworks.[14]

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

In August 2012 the AEMC published its second interim report, which addressed three broad issues:

- Generators' certainty of access to the network—the AEMC presented an option for generators to purchase 'firm' access from network business at charges reflecting the additional cost of providing capacity. Generators with firm access would be compensated by 'non-firm' generators or the network business if they are constrained from supplying electricity.
- Network planning—the AEMC proposed to enhance transmission planning and investment by expanding the role of the national transmission planner. The new functions would include reviewing network planning reports and RIT-T processes, providing demand forecasts for network planning, and assuming the Last Resort Planning Power from the AEMC. Additionally, the AEMC proposed networks be required to consult with each other and the national transmission planner on projects with interregional impacts.
- Network connection arrangements—the AEMC proposed to improve the information available to connection applicants, which would include publishing standard contracts and design standards. Applicants would have increased access to cost information, greater input into the selection of contractors, and the ability to determine how extension assets are provided.

The AEMC expects to release the final report prior to 31 March 2013.

2.9.3 Productivity Commission review of electricity network regulatory frameworks

In January 2012 the Australian Government directed the Productivity Commission (PC) to examine the efficiencies of using benchmarking in network regulation, and to assess whether the regulatory regime is delivering efficient interconnector investment. The PC's draft report (released October 2012) found:

- benchmarking, while not yet capable of replacing the current framework for setting network revenues, could be incorporated into existing processes to test network business proposals. The AER, in consultation with industry, has been developing key benchmark indicators for use in future regulatory reviews.
- interconnection is sufficient at present, but the current framework may not encourage efficient levels of interconnection in the future. It recommended amendments to the RIT-T to remove a bias against interconnection investment.
- changes to the regulatory framework may allow for more efficient use of interconnector capacity. It considered the recommendation in the AEMC's transmission frameworks review regarding optional firm access to transmission capacity should largely address this concern. Over the longer term, nodal pricing (where the price paid to generators varies within a region) should be considered.

Outside its terms of reference, the PC also recommended enhancing consumer participation by establishing an industry funded consumer body and encouraging greater demand side participation.

2.9.4 Interregional transmission charging

In February 2010 the SCER proposed a Rule change on interregional charging arrangements for transmission networks, to promote more efficient operation of, and investment in, the networks. 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 proposed Rule change would introduce a load export charge that effectively treats the business in the importing region as a customer of the business in the exporting region.

Consultation on the Rule change identified issues with existing transmission charging methods, including a lack of consistency in how charges are calculated across NEM regions. These issues could reduce the efficiency of the proposed scheme and make interregional charges more volatile. The AEMC is developing a uniform national interregional transmission charging regime to address these issues. It released a discussion paper in August 2011, setting out options. The AEMC completed modeling of the proposed options in October 2012 and presented a recommendation for the charging method. A final Rule determination is expected by February 2013.

2.9.5 Distribution network planning and expansion

The AEMC finalised a Rule change in October 2012 on a national framework for electricity distribution network planning and expansion, to support efficient investment decisions. The new provisions include requirements for distribution businesses to:

- annually review and report on network requirements for the following five years
- observe demand side engagement obligations, including consulting with non-network providers and considering their proposals
- undertake joint planning on common issues across networks.

The provisions also introduce a RIT-D, with dispute resolution through the AER (section 2.4.1).

2.9.6 Electric and natural gas vehicles

In 2011 the SCER requested the AEMC to identify energy market arrangements for the economically efficient uptake of electric and natural gas vehicles. The AEMC's draft report in August 2012 found existing market arrangements could accommodate natural gas vehicles. But, without appropriate price signals in place, electric vehicles could impose significant additional costs on the network that all customers would bear. The AEMC recommended introducing:

- separate metering of large loads (including electric vehicles) to allow for appropriate price signals and enable competition in the supply of energy for these loads
- metering arrangements to enable charging infrastructure to be installed on commercial properties.

The AEMC's final advice was expected towards the end of 2012.

2.9.7 Cost pass through arrangements

In October 2011 Grid Australia submitted a Rule change proposal to the AEMC requesting amendments to the cost pass through regime for electricity networks. It argued the networks are exposed to the risk of significant cost impacts from natural disasters and third party insurance liability claims that are beyond their reasonable control.

In August 2012 the AEMC finalised a Rule change that will enable a transmission network to nominate additional pass through events when it submits a revenue proposal to the AER (matching the current arrangement for distribution networks). The AER must have regard to specified considerations when determining whether to accept the pass through event. The Rule also allows networks to recover their efficient costs if a pass through event occurs in the final year of a regulatory period.