# 2 The structure and performance of the National Electricity Market

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| Key points |
| * The NEM comprises six groups of direct participants: generators, ancillary services, transmission and distribution networks, retailers and customers. * The structure of the electricity supply industry has shifted over time, with vertical separation of generation and retailing from the natural monopoly elements of the industry, and horizontal integration of network businesses. However, increasingly generators and retailers have integrated to form ‘gentailers’. * Collectively, state governments are still significant asset holders — owning all transmission and distribution assets in Queensland, New South Wales and Tasmania. * Network services are the most costly single component of electricity supply, accounting for around 45 per cent of total electricity prices. * From June 2007 to December 2012, real Australian retail electricity prices rose by around 70 per cent, with network costs playing an important role in the last few years, particularly for New South Wales. The initial part of this price surge occurred under state based regulatory regimes. * Any price increases in network services have particularly large relative effects on poorer households, one of the motivations for concerns about price pressures. * Residential network charges are diverging between jurisdictions. Network charges in New South Wales, Queensland and South Australia are projected to be around double those in Victoria in 2013–14. * Power consumption per customer fell by around 2.5 per cent in both 2010–11 and 2009–10. Peak demand to average demand has generally been rising over time. * New patterns of network development may occur as generation shifts away from conventional energy sources, with cost and planning challenges. * While rising network price pressures partly reflect peak demand trends, more undergrounding of lines, higher reliability requirements and the need for asset replacement, this does not mean that there is no scope for efficiency improvement. * Even modest improvements in network business efficiency could produce billions of dollars of economic benefits to Australians. * Network services are a ubiquitous input for all industries, accounting for around  1–1.5 per cent of the value of inputs for most industries. Given this dispersion of interests, it would be hard for a representative user group to form spontaneously and to negotiate from a position of power with network businesses. |
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This chapter provides a brief overview of the National Electricity Market (NEM) as a whole, covering the:

* structure of the NEM, including brief coverage of some recent developments in generation and retailing that are relevant to networks (section 2.1)
* scale of the network and its costs — the significance of which explains why cost pressures in this part of the electricity industry have large impacts on the prices customers face (section 2.2)
* characteristics of demand (section 2.3). This is important from many perspectives. It affects the capacity for consumers to exercise countervailing power and partially motivates new approaches to involve customers in the regulatory process (an issue explored in chapter 21). It shows why benefits from any lower network costs cascade across the entire community. And, given its nature as an ‘essential’ service, any cost pressures on network services have particularly adverse effects on low-income households under current pricing structures, underlining why network cost increases are so sensitive for the community
* recent price changes (section 2.4) and their proximate causes (section 2.5)
* basic reliability performance of the network (section 2.6), since customers value uninterrupted power and good frequency control. (In their own right, some governments’ requirements for improved reliability have also been a significant source of cost pressures)
* potential economic gains from improving the performance of the network — which motivates the value of the policy reforms outlined in subsequent chapters (section 2.7).

This chapter does not provide a detailed description of the regulatory environment governing networks, since this is addressed in a focused way in the policy chapters that follow.

## 2.1 The structure of the National Electricity Market

The NEM is a highly elaborate system for managing the production and transport of power throughout eastern Australia. On the supply side, there are four principal parts of the system: generation, network transmission and distribution services, and retail services (figure 2.1).

Figure 2.1 The structure of the National Electricity Market

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| Figure 2.1 The structure of the National Electricity Market. This figure shows the path of generated electricity to its end users in the National Electricity Market. |

*Data source*: Based principally on Powercor (2006).

### The network

The electricity network (the focus of this inquiry) is a massive transportation system that takes the power from generators and delivers it to an end user’s electricity switchboard. It comprises several parts:

* transformers, which take the power from the generators and convert it to high voltage (which lowers transmission losses when power is transported over any significant distance)
* high-voltage transmission lines — mainly strung overhead on steel lattice towers — that transport power over long distances. These include intra-regional lines and inter-regional lines (interconnectors)
* substations that convert very high voltage to lower voltage
* the myriad of lower‑voltage substations, poles, trenches and wires that make up the distribution system — the ‘capillaries’ of the system — which distribute lower voltage power to multiple users in local areas
* the provision and maintenance of certain services, such as street lighting
* meters at the business or household that record electricity consumption and, in some cases, provide real time control of the delivery of power to customers, and provide information on time-of-use prices to customers and usage patterns to suppliers. While distributors are mainly responsible for metering equipment and associated services, there is some competition from other businesses (Metropolis 2012).

Although the information technology systems to control the network are sophisticated (such as those deployed by the Australian Energy Market Operator (AEMO) and network businesses), much of the *cost* of the electricity network involves relatively mature technologies, such as trenches, poles and wires (a feature it shares with telecommunications). The research and development undertaken by electricity networks across Australia was estimated to be less than 1 per cent of value added or $50 million in 2008‑09 (just a little more than in the log sawmilling and timber dressing industry) (ABS 2011a).

#### Regulatory arrangements for networks

The regulatory arrangements for networks are highly complex. (The Australian Energy Regulator (AER) provides an accessible summary for readers of the key aspects of the regulatory framework.)[[1]](#footnote-1) The National Electricity Law and the Rules set out the NEM-wide arrangements for the economic regulation of networks. Reliability standards and planning are largely decentralised — and are overseen by the network businesses, state and territory regulators and their governments. The relevant aspects of these arrangements, (including around 200 pages of the Rules that are most important for this inquiry), are discussed in the chapters that follow and are, accordingly, not duplicated in this chapter. However, most of the roughly 1500 pages of the Rules have little bearing on this inquiry, as they cover market dispatch and financial settlement procedures, prudential requirements for market participants, administrative functions, power system security, connection arrangements, and system standards, among other matters.

### Generation and the spot market for electricity

Most power in the NEM is generated using coal (79 per cent of output) or gas (11 per cent out of output) as its fuel source (AER 2012q, p. 30, p. 32). However, carbon pricing (currently effectively achieved as a carbon tax on high CO2 emitters) and the renewable energy target are designed to encourage investment in more diverse and lower carbon-emitting sources of generation. While only accounting for 4 per cent of current power capacity (and 3 per cent of output) in 2011, wind generation is an increasingly important source of power (figure 2.2).

Figure 2.2 Growth in generation by fuel type

Australia, 1989‑90 to 2010‑11

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| Figure 2.2 Growth in generation by fuel type. This figure shows how generation sources have changed over time, by fuel type. While generators using black coal, brown coal and natural gas are by far the most important sources of power, wind generation has exhibited the highest growth rates in the last few years. |

*Data source*: BREE (2012).

Wind generation accounted for around two thirds of investment in new installed (summer) capacity in 2010‑11, around 45 per cent of the new capacity associated with committed investment in June 2011 and 65 per cent of capacity in publicly announced projects (table 2.1). In South Australia, wind accounts for nearly one quarter of nameplate capacity[[2]](#footnote-2) and has sometimes accounted for around 86 per cent of generation for a trading interval (but its overall contribution to energy output in that State is around 27 per cent).[[3]](#footnote-3) In contrast to the burgeoning role of wind generation, little new hydro capacity has been installed in the last decade, with similar future prospects. (However, existing hydro-electricity plants are important sources of energy in Tasmania, Victoria and New South Wales.) In 2010‑11, solar generation provided less than 1 per cent of Australia’s total generation output in this period (BREE 2012).

The greater diversity of generation has several implications for the electricity network. Much of the existing transmission infrastructure is close to the raw materials used to power conventional generators (such as the coal reserves in the Latrobe Valley and the Hunter Valley, and the rainfall and topography of the Snowy Mountains). That means that new transmission infrastructure may be required to connect renewables generators to the grid, sometimes across state boundaries. That then raises the issue of the best arrangements for regulating interconnectors (and likewise transmission generally — chapters 18 to 20). An associated issue is that while entry barriers to new generation are lower, incumbent generators may sometimes wield market power, affecting whether and where network businesses build new transmission lines.

Table 2.1 Investment in generation: installed and anticipated

|  |  |  |  |
| --- | --- | --- | --- |
| Fuel type | Installed in 2010‑11 | Announced in 2011 | Committed in 2011 |
|  | Share of summer MW capacity (%)a | Share of nameplate capacity (%)b | Share of nameplate capacity (%) |
|  | % | % | % |
| Brown coal | 0.0 | 4.1 | 0.0 |
| Natural gas | 35.5 | 26.8 | 43.7 |
| Bagasse/black coal | 0.0 | 2.3 | 10.7 |
| Geothermal | 0.0 | 1.3 | 0.0 |
| Solar | 0.0 | 1.7 | 0.0 |
| Hydro | 0.0 | 0.1 | 0.0 |
| Wind | 64.5 | 63.6 | 45.4 |
| Methane | 0.0 | .. | 0.1 |
| Total | 100.0 | 100.00 | 100.00 |

a The AER gave data for summer capacity only. This is the maximum power of a generator during summer (which can vary from other seasons, for example, due to the temperature of cooling water for thermal power plants). b Where a range of nameplate capacity (MW) was provided in the data, the lowest value was used. A generation investment is categorised as ‘committed’ by the Australian Energy Market Operator (AEMO) if most of the pre-conditions for future investment are in place (such as finance, land purchase, and contracts to build). Announced projects are ones that have a lesser degree of certainty, but an intention to build has been publicly made.

*Source*: AEMO (2011a); AER (2011b, p. 44).

The price of wholesale electricity is determined in a spot market in which demand and supply are constantly matched. Every five minutes, generators bid to supply a given quantity of power. With a few exceptions, all power supplied to the grid must be supplied through the wholesale spot market. Offers to generate are stacked in order of rising price, and are then scheduled and dispatched into production, though sometimes constraints on the technical capacity of the transmission network mean that generators can be scheduled out of price order (AEMO 2010f). Much of base load power is supplied by relatively low-cost large coal-powered generators that must run for 24 hours a day. During peak demand periods or where there are significant outages, the additional power required is supplied by switching on high-cost ‘peaking’ plants — usually gas turbines burning natural gas. Some generators are built only for extreme events, such as heat wave conditions, and may be idle for all bar a few hours a year.

The marginal cost of the last (highest priced) megawatt of electricity dispatched by AEMO determines the spot price. All generators receive the same spot price for their dispatched power, regardless of their bid price. Accordingly, a low bidder will typically receive revenue well above the marginal cost of their dispatched power. Such a premium is required to provide an ex ante incentive for investment in generators, though changes in demand, fuel costs and competitive technologies mean that ex post a generator may either receive more or less than was needed to justify the initial investment.

AEMO sets a spot price floor (-$1000 per MWh) and ceiling ($12 900 per MWh).[[4]](#footnote-4) The former is required because it can be costly to turn a generator off, so that a generator may want to guarantee dispatch by bidding at negative prices (although this feature also has some unintended impacts as discussed in chapter 19). The latter is required because demand is very unresponsive to price over the very short run (due to the way in which prices are signalled to customers and their capacity to respond to them). Without a price ceiling, prices would rise astronomically during extreme peak load events or times of reduced base load capacity (Frontier Economics 2010a), as would wholesale electricity costs. There is some concern that a large generator could use transient market power to withhold enough low-cost base load output to raise market prices for the residual amount of power it provides. The ceiling places a limit on that capacity.[[5]](#footnote-5) There is a further safeguard provision that limits the price to $300 per MWh (the administered price cap) if high spot prices are sustained.[[6]](#footnote-6)

### Retailing

The other major segment of the system — retailers — purchase electricity from the national market, pay access fees to networks, and sell power to end users. They manage billing, develop packages of services tailored for different customers and, through various risk management techniques, insure final customers against volatile electricity spot prices.

In contrast to network services, there is a genuine capacity for entry into retailing, and therefore greater scope for effective competition. Customers are able to choose their own retailers (‘full retail contestability’) in all NEM jurisdictions apart from Tasmania. Many retailers specialise in providing services to larger customers only, with less than 50 per cent of retailers providing services to small customers (AER 2011b, pp. 105‑6).

In most jurisdictions, a few retailers provide most of the services, with a particularly high concentration of supply in Tasmania and the ACT (AER 2012q, p. 118‑121). Victoria has the greatest level of competition, as indicated by customer switching patterns and a less concentrated market structure.

There has been an increasing shift to harmonised retail regulations across the NEM. In 2006, the Council of Australian Governments agreed to develop a new national framework governing the sale and supply of electricity and natural gas to retail customers. The goal was to reduce regulatory burdens for energy businesses operating across jurisdictions, while retaining appropriate consumer protection. A lengthy process of consultation, negotiation and regulatory development ensued after the 2006 agreement.

A National Energy Customer Framework (NECF) has now been (notionally) created. The NECF transfers several major regulatory functions currently performed by the relevant jurisdictions to the Australian Energy Regulator (AER), including:

* monitoring compliance and enforcing breaches of the National Energy Retail Law and its supporting rules and regulations
* authorising energy retailers to sell energy, and granting exemptions from the requirement to be authorised
* approving retailers’ policies for assisting with customers facing hardship
* providing an online energy price comparison service for small customers (see the energy price comparison website, Energy Made Easy)
* administering a national retailer-of-last-resort scheme, which protects customers and the market if a retail business fails
* reporting on the performance of the market and participants, including on energy affordability, disconnections and competition indicators.

As in other aspects of the NEM, the ‘N’ in the NECF remains somewhat ethereal. Implementation across jurisdictions has been slow. By July 2012, the largest states had yet to pass the legislation, with the law commencing only in the ACT and Tasmania at that time (AER 2012q, p. 119). South Australia adopted the NECF in February 2013. As in the case of network regulation, the NECF excludes Western Australia and the Northern Territory.

Moreover, the NECF also provides scope for jurisdictions to carve out aspects of the National Energy Retail Law. For example, the Victorian Government will not adopt the prepayment meter regime and will maintain certain consumer protections that it considered superior to those in the NECF (DPI 2012a).

And while the AER will take over the non-economic functions of retail regulation, retail price regulation remains a state and territory government responsibility. In 2006, the Council of Australian Governments agreed to remove retail price regulations in any jurisdiction where the Australian Energy Market Commission (AEMC) found competition was effective. However, that process has not moved quickly. Jurisdictions have not always acted when the AEMC has proposed de-regulation following its assessment that competition was effective. The ACT Government did not accept the AEMC’s recommendation to deregulate prices, and the South Australian Government took five years to implement the AEMC recommendation. In June 2011, the Standing Council on Energy and Resources announced that future reviews would be New South Wales in 2012, Queensland in 2013, the ACT in 2016, and Tasmania no sooner than 18 months after full retail contestability is implemented.[[7]](#footnote-7) The upshot is that retail price regulation remains in all jurisdictions other than Victoria (AER 2012q, p. 126) and South Australia. Under regulated arrangements, customers can choose to purchase their electricity from the ‘non-market’ retail segment, which is subject to price controls by the relevant state regulator, or the market segment, in which there is pricing flexibility.

As in other aspects of electricity supply, imperfections in one part of the system carry over to other parts. By acting as an obstacle to cost-reflective pricing and incentives for adopting direct load control, retail price controls adversely affect the efficiency of investments in electricity network and generation (chapter 12). As emphasised in chapter 1, this affects the use of benchmarking in incentive regulations, but also raises the importance of testing the cost effects of different regulatory regimes across the NEM.

#### Benchmarking in retailing

Benchmarking has been incorporated into the national approach to retailing (ACIL Tasman 2011 and EnergyConsult 2010), and is based on survey data from more than 5000 households on their power use. The purpose of the ‘Electricity Bill Benchmarking initiative’ is to provide households with information on their relative use of power given their household characteristics, so that they can make informed choices about their electricity use.

The initiative reveals some of the inconsistencies in the goals of policies across the electricity supply industry. Relatively short periods of peak use, mainly during hot summer days, are responsible for a significant amount of network infrastructure investment (chapter 9). However, the information provided in the retail benchmarking exercise concerns total power usage, which is a poor proxy for expensive peaky use. Accordingly, the information does not inform consumers about the true underlying costs of their power usage. If critical peak pricing were introduced — as recommended by the Commission — the retail benchmarking model would need to be elaborated. The Commission has recommended surveys to estimate the value of lost load[[8]](#footnote-8) for setting appropriate reliability standards (chapter 14). These surveys could replace the existing electricity bill benchmarking surveys, and would provide better information to assist informed choice by consumers

### Other services

Outside these major parts of the system, there are some direct transmission lines from generators to major industrial users, some industrial co-generation feeding into the grid, increasing micro-generation at the customer end (such as solar panels) and an array of financial and technical services (for example, in financial instruments that address the risks, mainly related to pricing, of generators, retailers and ancillary services[[9]](#footnote-9)).

### Ownership and linkages

Competition reform in the 1990s led to the disintegration of the management of the electricity system in each state and territory by a single vertically integrated state-owned business (spanning generation, transmission, distribution and retailing).

Generation and retailing are now open to competition, while the natural monopoly segments of the industry — network services — remain heavily regulated and are often still owned by governments (figure 2.3). The New South Wales, Queensland and Tasmanian governments own the distribution networks in their states. In contrast, private entities own the South Australian and Victorian distribution networks (though the former involves a long-term leasehold rather than outright ownership). The ACT distributor is part government-owned. Overall, governments own around 75 per cent of distribution assets in the NEM (and a similar share of transmission assets).

Figure 2.3 Participants in the National Electricity Market

By ownership and market sharea

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| Origin  Energy  (  multi  -  region  )  Origin  Energy  (  multi  -  region  )  TRUenergy  (  multi  -  region  )  TRUenergy  (  multi  -  region  )  AGL  (  multi  -  region  )  AGL  (  multi  -  region  )  Inter  -  national  Power  (  Vic  ,  SA  )  Inter  -  national  Power  (  Vic  ,  SA  )  Other  generators  Other  generators  Electranet  (  SA  )  Electranet  (  SA  )  SP Ausnet  (  Vic  )  SP Ausnet  (  Vic  )  SA Power  Networks  (  SA  )  SA Power  Networks  (  SA  )  Origin Energy  (  multi  -  region  )  Origin Energy  (  multi  -  region  )  Powercor  ,  SP AusNet  Powercor  ,  SP AusNet  AGL Energy  (  multi  -  region  )  AGL Energy  (  multi  -  region  )  TruEnergy  (  multi  -  region  )  TruEnergy  (  multi  -  region  )  Other  retailers  Other  retailers  **Delta and Mac**  **Gen**  **(**  **NSW**  **)**  **Transgrid**  **(**  **NSW**  **)**  **Essential**  **(**  **NSW**  **)**  **Snowy**  **Hydro**  **(**  **Vic**  **,**  **NSW**  **)**  **AETV**  **&**  **Hydro**  **Tas**  **(**  **Tas**  **)**  **CSE and**  **Stanwell**  **(**  **Qld**  **)**  **Transend**  **(**  **Tas**  **)**  **Powerlink**  **(**  **Qld**  **)**  **AusGrid**  **(**  **NSW**  **)**  **Endeavour**  **(**  **NSW**  **)**  **(**  **a**  **)**  **(**  **Tas**  **)**  **Energex**  **(**  **Qld**  **)**  **Ergon**  **(**  **Qld**  **)**  **Aurora**  **(**  **Tas**  **)**  **Ergon**  **(**  **Qld**  **)**  (  a  )  Aurora Energy distribution  Transmission  Generation  Distribution  Retail  Private ownership  ActewAGL Public  -  Private  Joint Venture  Public  (  planned to  be privatised  )  Public ownership |

*Source*: Queensland Commission of Audit (2013, figure 2, p. 13).

Moreover, there are still strong ownership and management links between parts of the system. Vertical integration between generators and retailers — ‘gentailers’ — is becoming increasingly common (AER 2012q, p. 40, pp. 119‑24; Pearce 2011, p. 16), as is integration into fuel supply. For example, Origin Energy — one of Australia’s largest energy businesses — has integrated operations spanning gas exploration and extraction, gas pipelines, power generation and electricity retailing. AGL Energy and EnergyAustralia also have interests in gas production and/or gas storage that complements their interests in gas fired electricity generation and energy retailing.

State governments also sometimes jointly own transmission, distribution, generation and retailing. For example, the Tasmanian Government owns the sole transmission business in that State (Transend), the overwhelming majority of generation capacity (principally through Aurora Energy and Hydro Tasmania), the only distribution business (Aurora Energy), the dominant small customer retailer (Aurora Energy) and a major business retailer (Momentum Power). However, following a recent review (Electricity Supply Industry Expert Panel 2012a), the Tasmanian Government will sell Aurora Energy’s retail arm and combine the distribution network with transmission (Green 2012, AER 2012q, p. 60). In most other states, there is usually greater scope for competition from private businesses in the contestable parts of the system (generation and retailing).

The vertical separation of networks from the other parts of the electricity system has had many desirable benefits, including the capacity to develop a genuinely national market and to provide stronger market-based incentives for efficiency. However, it has also diminished the capacity for coordination of the various parts of the networks and has reduced economies of scope.[[10]](#footnote-10) For example, exploitation of transmission congestion; weakened incentives for demand management; difficulties in planning; and the requirements for sophisticated financial hedging instruments reflect the problems that vertically separated businesses have in transacting with each other. Many of the regulations in the NEM can be seen as alternative ways of encouraging efficient transactions between businesses that no longer have aligned interests. This poses fundamental challenges for regulatory design — some of which have not yet been fully resolved, such as regulations for smart meter rollouts (chapter 10) and strategic bidding behaviour by generators (chapter 19).

While policy reforms have required vertical disintegration, governments as owners have encouraged horizontal integration of network distribution businesses. This appears to reflect significant economies of scale in networks[[11]](#footnote-11) and the progressive shift from local small generators to large-scale generators more remote from population centres. In New South Wales, the merger process has been the most pronounced (figure 2.4). However, mergers involving common management appear to have been confined to businesses within state boundaries, reflecting the importance of state ownership (and a state-specific orientation to service delivery).[[12]](#footnote-12) There is no obvious reason why common management of businesses should be constrained by state borders. In the United States — at least among transmission businesses — the story is quite different. For example, American Electric Power owns transmission infrastructure throughout the United States and Canada. This raises the question of whether state-ownership may be a barrier to efficient horizontal mergers (chapter 7).

Figure 2.4 Progressive merger activity

NSW, distribution businesses 1945‑2014

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*Data source*: NAS (2009).

## 2.2 The scale of the network and its costs

In 2011‑12, 308 generators with an installed capacity of more than 48 000 MW fed 9.7 million customers through the network of five jurisdictional transmission networks, 13 major distribution networks and 6 interconnectors (AER 2012q, p. 28, p. 61). Collectively, state governments are significant asset holders in all of the above segments of electricity supply. The NEM accounts for around 90 per cent of the line length of the entire Australian electricity distribution system and provides energy to about the same share of Australian customers (Wessex Consulting 2010). The actual and forecast regulated network revenues summed over the (mostly five‑year) regulatory periods that were still in force in late 2012 was $62 billion in June 2011 prices — $14 billion for transmission businesses and $48 billion for distribution businesses (AER 2012q, pp. 62‑3). (Taking account of the slight variation in the regulatory periods, the average *annual* revenue was $12.2 billion.)

The NEM is one of the most geographically dispersed electricity networks in the world (figure 2.5). The network comprises more than 40 000 kilometres of high voltage transmission lines and 770 000 kilometres of lower voltage distribution networks (AER 2012q, pp. 60ff). There are also around 1500 kilometres of interconnectors that transmit power from one jurisdiction’s electricity system to another, thus creating the ‘national’ market. To give a perspective on this, in the United Kingdom, there are around 25 000 kilometres of transmission lines and 800 000 kilometres of distribution lines serving a population of more than three times that of the NEM (UK Department of Energy and Climate Change 2011).

The total asset value of the NEM network was around $60 billion in 2010, with an expected five yearly investment of more than $40 billion (in 2011 prices — table 2.2). The distribution network accounted for around 75 per cent of the total network assets and nearly 85 per cent of investment. This is why concerns about the efficiency of investment mainly relate to distribution networks. Interconnectors account for an estimated share of total network asset values of around 5 per cent. Transmission accounts for the residual network assets and investment.

There is less information about other aspects of network businesses in the NEM because the AER concentrates on investment, assets, and regulatory revenues, rather than broader measures of the importance of the industry.[[13]](#footnote-13) Value added is estimated to be around $10.7 billion in 2010‑11.[[14]](#footnote-14)

Employment in network businesses was around 30 000 at 30 June 2011, but this is for all jurisdictions, not just the NEM (ESAA 2012, p. 10). Given that the NEM accounts for around 90 per cent of total customers (Wessex Consulting 2010), a reasonable employment estimate for NEM businesses is around 27 000. Somewhat dated Australian Bureau of Statistics (ABS) information on the industry for June 2007 suggests a number consistent with this (table 2.3).

Figure 2.5 Transmission network infrastructure in the NEM

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| Figure 2.5 Transmission network infrastructure in the NEM. This figure shows the broad geographical locations of transmission network infrastructure in South Australia, Queensland, New South Wales, the Australian Capital Territory, Victoria and Tasmania. |

*Data source*: AER (2009a, p. 126).

Table 2.2 Assets and investment in the NEMa

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
|  | Asset value circa 2010 (billion) | Estimated investment circa 2010 | Investment rate (investment to assets) | Share of total assets | Share of total invest. | Segment’s contribution  to electricity  price 2010‑11f |
|  | $ billion 2011 prices | $ billion 2011 prices | % | % | % | % |
| Generationb | 40.0 | 1.2 | 3.0 | 39.0 | 12.1 | 34.5 |
| Transmission and interconnectorsc | 16.7 | 1.5 | 8.9 | 16.3 | 14.9 | 7.7 |
| Distributiond | 45.8 | 7.2 | 15.8 | 44.7 | 73.0 | 37.3 |
| Total for above componentse | 102.4 | 9.9 | 9.7 | 100.0 | 100.0 | 79.5 |

a The asset data for networks relate to the regulatory asset base at the beginning of the regulatory period. The beginning of the regulatory period varies by business, but its mean value is around 2010. The data are in June 2011 prices (AER 2012q, pp. 62‑63). b The asset values are for 2008 for the major power generators in the NEM, which account for nearly 100 per cent of installed capacity (NGF 2011, p. 1). The investment relates to the data available so far for 2011‑12 for all commissioned generators in the NEM (AER 2012q, p. 54). c The estimates for investment are one fifth of the investment for the five yearly regulatory period. The estimates also exclude any investment by Directlink, Murraylink and Basslink. However, these interconnectors amounted to only around 8 per cent of the total asset base for all transmission and interconnector assets. That, and the fact that it is known that little investment has occurred in interconnectors, suggests that the estimates will be close to its correct magnitude. d The estimates for investment are one fifth of the investment shown for the five yearly regulatory period. e The data exclude other cost contributors to electricity prices, such as feed-in tariffs, renewable energy target subsidies and, most importantly, retail costs. The Commission could not find data on assets and investment for the retail segment of the market. However, this segment mainly comprises operating expenses, rather than physical capital investments. The overall contribution of the retail segment to electricity bills is about 15 per cent, so the asset share is likely to be much smaller than this. f These values are estimated as each segment's share of the Australia-wide price per KWh. The three cost sources do not add to 100 per cent because some other cost influences, such as retailing, are excluded. The generation share is estimated as the wholesale share.

Average annual employee benefits are estimated to be around $128 000 per person in 2010‑11 (based on adding wage inflation rates to the data from table 2.3).[[15]](#footnote-15)

## 2.3 The nature of demand

Power consumption has been falling in recent years.[[16]](#footnote-16) The ESAA (2012) estimates that consumption per customer fell by around 2.5 per cent in both 2010‑11 and 2009‑10. Indeed, even total consumption fell in these two years despite rising population and household formation. (The implication is that, all other things being equal, unit prices must rise to cover the high fixed costs of network infrastructure.) Supply-based data suggest that this pattern has persisted in the year from 2010‑11 to 2011‑12 (AER 2012q, p. 28).

Table 2.3 The significance of electricity networks

2006‑07, Australia-wide, current pricesa

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
|  | Unit | Generation | Transmission | Distribution | Retail | Electricity supply |
| Employment end June | No. | 9 487 | **2 572** | **27 223** | 4 620 | 43 902 |
| Labour costs | $m | 1 074 | **307** | **2 914** | 358 | 4 653 |
| Sales & service income | $m | 10 776 | **2 180** | **13 506** | 13 053 | 39 516 |
| Value added | $m | 5 075 | **1 595** | **6 857** | 1 036 | 14 564 |
| Gross fixed capital formation (GFCE) | $m | 2 662 | **1 175** | **4 371** | 321 | 8 528 |
| Employee benefits per worker | $ | 113 208 | **119 362** | **107 042** | 77 489 | 105 986 |
| GFCE share of value added | % | 52.5 | **73.7** | **63.7** | 31.0 | 58.6 |
| Industry value added per person employed | $m | 534 943 | **620 140** | **251 883** | 224 242 | 331 739 |
| Profit margin | % | 13.6 | **20.7** | **22.2** | 1.2 | 12.8 |

a The full definitions of these terms are in the ABS publication below (pp. 37‑47) and have not been reproduced. Labour costs are the full cost of employment (of which of around 90 per cent are wages and salaries). ‘Value added’ represents the additional increment of value to the intermediate inputs used by the industry. Gross fixed capital formation is measured by the total value of a producer's acquisitions, less disposals, of fixed assets during the reference period (and so is not equivalent to investment in new capital). The profit margin is the percentage ratio of operating profit before tax to sales and service income.

*Source*: ABS (2008).

In contrast to average demand, the ratio of peak demand to average demand has generally been rising over time,[[17]](#footnote-17) reflecting the increasing penetration of air conditioning and the value people place on cooling during hot days (Topp and Kulys 2012, p. 42). This is a significant determinant of increased investment because networks must be built for peak use (AER 2012q, p. 15).

There were around 9.1 million electricity customers in 2010‑11, up by around 1 per cent from the previous year (table 3.2 in ESAA 2012).[[18]](#footnote-18) While around 90 per cent of customers are residential (some 8.1 million), these account for about 30 per cent of total consumption.

The importance to network businesses of the *demand* by various industries is quite different from the importance to other industries of the *supply* of network services.[[19]](#footnote-19) As far as the:

* former is concerned, network businesses have a wide customer base, although some industries, such as non-ferrous metal manufacturing and non-ferrous mining are particularly important revenue sources
* latter is concerned, of all industries that supply inputs to other industries, network services are characterised by close to the most uniform pattern of use (figure 2.6). Network services account for around 1‑1.5 per cent of the value of inputs for the bulk of industries, although they are more important inputs for a few industries, such as ceramics and glass manufacturing (figure 2.7).

The implication of this pattern of use is that any individual business user has relatively little capacity to negotiate from a position of power with network businesses. However, the Major Energy Users (sub. DR66) and the Energy Users Association of Australia (sub. 24) have nevertheless been able to act as stakeholders in requesting Rule changes and in representation during the regulatory process. In comparison, in the case of another regulated industry, airports, the number of direct users is small, and there is a much greater capability for negotiated arrangements.

An issue in this inquiry is whether network customers could play a larger role in determinations, drawing on the information of benchmarking, and with resort to the regulatory powers of the AER as the ‘stick’. Given the fragmented customer base, achieving that outcome requires a policy stimulus (chapter 21). The other implication of the pattern of use is that network businesses probably have little genuine capacity to ‘hold-up’ the investments of their customers — an issue relevant to the rationale for, and design of, the regulations (chapter 3 and appendix B).

Another facet of demand is its responsiveness to prices, which is relevant to the economic efficiency of addressing any network inefficiencies.

Figure 2.6 Network services are general-use inputs

2007‑08a

|  |
| --- |
|  |

a The measure of specificity is calculated as follows. Let there be N industries. Define an input share () each industry in the total intermediate inputs (TotalUse) of each other industry:

for

For any given industry (m) in the group 1 to N, there will be a vector of alpha values (**Vm**) representing the importance of that industry as an input into other industries (m1, m2, m3, … mN). Calculate the ratio (Rm) of 20th and 80th percentiles of **V**m. Were a given input industry to account for one per cent of the total intermediate use of each other industry, then Rm =1. That means that industry m would be a general-use input. In contrast were Rm to be small then it implies that many industries make little use of that input and some a large amount — a high level of specificity. The data show that electricity network services are a general-use input (though typically a small share of each industry’s total inputs – as shown in figure 2.7). Indeed, it is close to being the most general-use input among the large group of industries covered by the ABS input-output tables.

*Data source*: ABS (2012b).

Figure 2.7 Network services are a small share of inputs for most businesses, 2007‑08a

|  |
| --- |
| Figure 2.7 Network services are a small share of inputs for most businesses, 2007-08. This figure shows the share of total network services used by industries and corresponding intensity of use of the network services. |

a Based on table 5, industry by industry flow matrix with direct allocation of imports (so that the table relates to domestically produced network services only). The shares relate to intermediate inputs into industries. The horizontal axis shows that network services are a relatively small share of total intermediate inputs of most industries. The vertical axis shows that, with one exception — non-ferrous metal manufacturing — networks rely on a wide range of industries for their revenue. .

*Data source*: ABS (2012b).

Demand is not very responsive to prices in the short run, with a 10 per cent increase in prices likely to reduce electricity demand by somewhere between 2 and 4 per cent. The reduction is significantly greater — somewhere between 5 and 7 per cent — over the long run (Fan and Hyndman 2010, p. 8; Langmore and Duffy 2004). It is higher again for peak periods (PC technical paper). Consequently, some of the recent falls in electricity demand may reflect the impacts of the large price increases described in section 2.4. There is also significantly greater responsiveness to time-based tariffs, which shift demand from one period to another, rather than necessarily reducing daily demand by much. The responsiveness of demand to income is important for considering the distributional outcomes of any price reductions from reforms of network regulation. It appears that levels of electricity consumption are not very sensitive to income compared with most other goods and services. Consequently, the share of income spent on energy use falls significantly as household income rises (figure 2.8).

Figure 2.8 Lower-income households are hit harder by rising prices

|  |
| --- |
| Australia 2009‑10a |
| Figure 2.8 Lower-income households are hit harder by rising prices. This figure comprises of two charts. The first chart compares the electricity share of a total household income in Australia by equivalised disposable household income quintiles. The second chart shows the percentage of household income spent on energy costs in Sydney and surrounding regions for 2012 13, showing the median for each income bracket. The chart shows that the percentage of total household income decreases in higher-income households. As electricity costs are a much greater share of their disposable income, lower income households are hit harder by rising prices. |
| Sydney and surrounding regions, 2012‑13b |
| 12  10  8  6  4  0  2  $14 to  $20k  $20 to  $38k  $38 to  $46k  $46 to  $69k  $69 to  $98k  $98 to  $145k  $145 to  $174k  $174k  14  Median all households  Median  90th percentile  10th percentile  Energy expenditure as a share of post-tax income (%)  Household income (2012-13 $, before tax) |

a Equivalised income quintiles take account of household size and composition in determining the values of income and spending in each quintile (ABS 2011b, p. 46ff). The ABS publishes aggregate household energy use (non-transport) on an equivalised income basis, but does not do so for domestic electricity use alone. However, both measures of energy use are available for non-equivalised household income quintiles, and these data have been used to estimate electricity usage on an equivalised basis. Note that the data for quintiles are averages. Many households in each group will be spending a greater (or lesser) share of their incomes than those shown. Higher than average spending shares are particularly relevant for the lowest income quintile. b Households have a distribution of spending from high to low. Percentiles measure the spending at various points in that distribution. For the lowest income group ($14 000 to $20 000), 10 per cent of households have a spending level below around 4 per cent of their household income (the 10th percentile), while 10 per cent of households in this income group have spending above 14 per cent of their income (the 90th percentile).

*Data sources*: ABS (2011b); IPART (2012a, p. 13).

Domestic energy use accounts for more than 4 per cent of household income for the lowest quintile and less than 1 per cent for the highest quintile, or a ratio between the two of around 5.3 to 1. Other analysis suggests that this ratio is the third highest among the 35 broad commodity groups in the ABS Household Expenditure Survey — suggesting the inherently ‘essential’ nature of energy. More disaggregated analysis by the Independent Pricing and Regulatory Tribunal (IPART) for the Sydney region reveals that electricity spending can be as high as 14 per cent of income for the poorest households.[[20]](#footnote-20) This income pattern of consumption is one of the reasons why concerns about network efficiency and their flow-on price effects have been given such prominence.

## 2.4 Prices have been rising

Concerns about rapidly rising electricity prices have been a major source of concern to governments, businesses and the general community (figures 2.9, 2.10, and 2.11). Until the mid-2000s, Australian retail electricity prices grew at around the same rate as economywide inflation, but then began to rise rapidly. From June 2007 to December 2012, Australian retail electricity prices rose by around 100 per cent, while general inflation increased by around 16 per cent, so that real electricity prices rose by around 70 per cent. (Box 2.1 explains what real prices mean.) Electricity prices facing businesses have also risen strongly, albeit by not the same degree.[[21]](#footnote-21)

Electricity retail prices rose most strongly in Victoria (109 per cent) and New South Wales (111 per cent) over this period, more than 10 percentage points higher than any other jurisdiction in the NEM (figure 2.11). Future retail electricity prices in the NEM — at least partly locked in through regulatory agreements — are projected to increase by 21 per cent from 2011‑12 to 2014‑15 (AEMC 2013a, p. vi)

Growth rates in retail electricity prices accelerated in 2007 for Melbourne and Hobart, 2006 for Brisbane and Canberra, 2008 for Sydney and in 2010 for Adelaide. In all but the last case, the regulatory determinations in force had been authorised by state-based regulators,[[22]](#footnote-22) not the AER (and therefore were not encumbered by any unique flaws in chapter 6 of the Rules). While the Rules may have contributed to recent and forthcoming electricity prices, the price growth that preceded the new regulatory arrangements originated from other sources.

Community concerns about electricity prices have been accentuated by their coincidence with similarly large increases in the costs of other regulated essential services — water and sewerage (74 per cent from June 2007 to December 2012) and gas and other fuels (64 per cent over the same period).

Figure 2.9 Electricity prices

December 1980 to December 2012

|  |  |
| --- | --- |
| Business and household electricty pricesa | Real household electricity pricesb |
|  | |

a Data are from December 1980 to December 2012, rebased so that December 1990 = 100. The data relate to all Australian electricity prices, not just those in the NEM, but the trends will be similar. b ’Real’ prices are household prices divided by the CPI average for capital cities. The index shows how much electricity prices have increased above inflation.

*Data sources*: ABS (2012e, 2012f).

Figure 2.10 The price explosion

Annual growth rates (December 1981 to December 2012)

|  |
| --- |
|  |

*Data source*: Figure 2.8.

Figure 2.11 Relative residential electricity prices by NEM jurisdiction

December 1980 to December 2012

|  |  |
| --- | --- |
|  |  |

*Data source*: ABS (2012e).

|  |
| --- |
| Box 2.1 What are electricity prices? |
| It is important to clarify what household ‘prices’ denote. This report uses the standard ABS definitions. Unless otherwise stated, the price of electricity at any given time is the charge levied for power use by a household (or an index of this price), taking account of connection fees that are included in the price (ABS 2011c, p. 64). Both concessional and standard rates are included in the ABS approach. The ABS produces series only for capital cities and the Australian total is the weighted average of these series. The prices are the final retail prices, and incorporate wholesale costs (generation), network charges and retail margins, among some other costs.  While statistical agencies avoid the nomenclature, the ratio of the electricity price index to the consumer price index is sometimes referred to as the ‘real’ price of electricity. This is a relative price measure, not a price per se. As it indicates how far electricity prices have shifted relative to prices in general, it identifies the price pressures unique to electricity. We explicitly indicate when we use relative or ‘real’ prices to distinguish them from the conventional meaning of prices. Note that where the percentage price increase between period t and t+n is e and the inflation rate over the same period is c, then the relative price change is (e‑c)/(1+c). Given this complexity, it is sometimes better to give e and c as separate (or at least as complementary) measures, especially in cases where real prices may be hard to interpret. For example, when comparing price movements *between* states, real price differences will reflect both changes in electricity prices in different states and changes in their separate CPIs. Similarly, a real producer electricity price might use an average business input price index as the denominator, which may be quite different from the CPI.  Ergon Energy pointed out some problems in interpreting retail electricity prices (sub. 8, p. 12), though these concerns are not likely to affect the broad patterns identified in the ABS data. |
| *Source*: ABS (2011c). |
|  |
|  |

Many people are unaware that the costs of generating power are not the major contributor to their electricity bills. In 2011‑12, the costs of network services represented between 34–56 per cent of the typical annual household electricity bill across the various jurisdictions in the NEM (and around 45 per cent for the entire NEM) (table 2.4; AEMC 2013a).[[23]](#footnote-23) This represented a household cost for network services of between $350 to $700 per year.[[24]](#footnote-24)

In contrast, wholesale electricity prices from generators accounted for an average share of NEM-wide costs of around 35 per cent. The introduction of carbon pricing — which raises wholesale prices (generation costs) and retail margins — does not alter the relative importance of wholesale versus network costs to any great extent (figure 2.12). (Moreover, changes to its design announced recently are further likely to reduce its relative influence compared with network cost pressures.)

Apart from Victoria and the ACT, network costs have been the largest contributor to price increases since 2010 (AEMC 2011a; AER 2011b, pp. 4‑5, 20). For example, in New South Wales, network costs accounted for 80 per cent of the price increase in 2010‑11 and 50 per cent in 2011‑12. In contrast, in Victoria, changes to network costs had, at best, marginal impacts on electricity prices in 2011. The AEMC has forecast a similar pattern until 2014‑15, with the exception of New South Wales, where the contribution of network costs to rising electricity costs is predicted to abate (table 2.4).

Table 2.4 Projected network costs 2011‑12 to 2014‑15

|  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  | Network costs | | |  | Network share of total residential electricity costsa | |  | Contribution to price increases from 2011‑12 to 2014‑15b | |
|  | 2011‑12 | 2014‑15 | Increase |  | 2011‑12 | 2014‑15 |  | Distribution | Transmission |
|  | Cents/kWh | | % |  | % | % |  | % | % |
| Qld | 11.0 | 14.6 | 32.7 |  | 49.8 | 52.3 |  | 58.6 | 3.4 |
| NSW | 14.1 | 16.0 | 13.5 |  | 55.5 | 51.6 |  | 0 | 33.9 |
| ACT | 7.3 | 8.9 | 21.9 |  | 43.2 | 44.1 |  | 33.3 | 15.2 |
| Vic | 9.8 | 13.2 | 34.7 |  | 34.0 | 37.5 |  | 51.6 | 1.6 |
| SA | 13.8 | 18.2 | 31.9 |  | 46.2 | 54.7 |  | 108.8 | 20.6 |
| Tas | 14.2 | 17.5 | 23.2 |  | 54.2 | 56.3 |  | 40.8 | 26.5 |
| WAc | 9.0 | 10.7 | 18.9 |  | 34.4 | 36.0 |  | 31.4 | 17.1 |

a The cost shares in 2014‑15 are affected by the introduction of carbon pricing, which raises wholesale electricity prices and the retail margin (but also involves some offsets). b The estimates are calculated as the change in the cost of power (in cents per kWh) attributable to transmission and distribution as a share of the total increase in the cost of power over the relevant period. c Electricity prices in Western Australia relate to the South West Interconnected System (SWIS). The prices in this state exclude the tariff equalisation contribution to areas outside the SWIS, as these represent transfer payments rather than cost-related prices.

*Source*: AEMC (2013a).

Figure 2.12 Projected residential price cost components in 2014‑15, Australia

Cents per kWh

|  |
| --- |
|  |

*Data source*: AEMC (2013a).

Transmission costs are far lower than distribution costs, and so their projected contribution to overall electricity price growth is muted. However, as noted by industrial businesses, the significance of transmission costs may be much greater for businesses close to the transmission supply point (Energy Consumers Group 2011, p. 9).

There are significant differences in the costs of network services in various jurisdictions. By 2014‑15, the AEMC forecasts that total network costs in cents per kWh in Queensland, New South Wales, South Australia and Tasmania will be 11 per cent, 21 per cent, 38 per cent and 33 per cent higher respectively than the costs in Victoria. Much of the debate about network performance rests on the degree to which these gaps reflect excessive and inefficient costs or different operating conditions and capital vintages (chapter 6).

Notably, AEMC data show that the disparities between network costs appear to be growing over time, instead of converging (unlike other costs, which are converging). Given that the physical environment of businesses do not change rapidly over time,[[25]](#footnote-25) spatial differences in the topography and climatic conditions of network businesses cannot readily explain this divergence (figure 2.13).

## 2.5 The proximate reasons for higher network charges

Some of the contributors to network price increases have reflected input cost increases, which are typically outside the control of either network businesses or government. For example, rising steel, copper and (to a lesser extent) aluminium prices have increased costs (AER 2009a, pp. 485ff; Plumb and Davis 2010; figure 2.14). Wage rates for public sector electricity, gas and water utilities have increased at a faster rate than wages in their private sector counterparts, and all industries (figure 2.14).

Since they are determined as part of the regulatory process, increases in the regulated weighted average cost of capital are also major determinants of regulated revenues, and of resulting prices (chapter 5).

Above all, lower productivity appears to have been a major pressure on network charges. In recent years, the stock of electricity infrastructure has risen rapidly and, unusually by historical experiences, labour inputs have risen. As output has not risen as rapidly as average inputs, measured industry efficiency has fallen, and with it, prices per unit of power have risen. While it is less clear what has happened to the multifactor productivity (MFP)[[26]](#footnote-26) of network services specifically, most of the factors driving lower productivity in the electricity industry appear to relate to the network (Topp and Kulys 2012). Evidence from IPART (2010) supports this, finding that in New South Wales there were more pronounced productivity reductions for network businesses than for generators. Topp and Kulys identify three phases of multifactor productivity growth in the electricity industry (figure 2.15):

* moderate growth phase from 1974‑75 to 1985‑86
* a rapid growth phase from 1985‑86 to 1997‑98
* a negative growth phase 1997‑98 to 2009‑10.

Figure 2.13 Network costs differ between businesses and the gap is wideninga

|  |
| --- |
| Overall change from 2010‑11 to 2013‑14 |
|  |
| Convergence — year by year change from 2010‑11 to 2013‑14 |
|  |

a Network costs are the sum of the transmission and distribution costs for each business. The top graph shows that businesses with costs well above the NEM average in 2010‑11, tended to have faster forecast percentage growth rates in costs from 2010‑11 to 2013‑14. Given this depiction of the data can sometimes give biased estimates of the extent of convergence or divergence (Friedman 1992), measures of so-called σ‑convergence rigorously test whether convergence is present or not. σ-convergence occurs when the coefficient of variation between states declines over time. In this case, the data reveal divergence. The data are based on the AEMC’s forecasts made in 2011 (rather than its more recent 2013 forecasts, reflecting that no data at the business level was published.

*Data sourcse*: AEMC (2011a) and PC estimates.

Figure 2.14 Input prices

June 1998 to June 2012

|  |  |
| --- | --- |
|  |  |

*Data sources*: ABS (2012a; 2012d).

Figure 2.15 Measured electricity sector productivity has been falling

1974‑75 to 2009‑10

|  |  |
| --- | --- |
| Comparative productivity performancea | Input and output growth in electricity |
| Figure 2.15 Measured electricity sector productivity has been falling. This figure comprises of two charts. The first chart compares the productivity index of electricity to the market sector between 1974 75 and 2009 10. The second chart compares the input index of output, capital, weighted inputs and labour  between 1974 75 and 2009 10. | Measured electricity sector productivity has been falling.This chart compares the input index of output, capital, weighted inputs and labour  between 1974-75 and 2009-10. |

a Multifactor productivity estimates are increases in real output after taking account of changes in labour and capital inputs. The market sector includes all industries, with the exception of a few industries (public administration and defence), where reliable measures of productivity are difficult to calculate.

*Data source*: Topp and Kulys (2012).

Much of the negative growth rate appears to reflect capital growth without commensurate measured output growth. At face value, that suggests inefficiency. However, at least some of the growth in the capital stock reflects replacement capital for ageing assets, and new capital to meet the demand for greater reliability levels, growing peak demands, and requirements for greater undergrounding of lines (noting that underground lines are significantly more costly than overhead lines). Network businesses pointed to some of these pressures (for example, Ergon Energy, sub. 8, p. 11). The ABS’s output measures for electricity fail to take account of the value of customer reliability, the benefits of undergrounding or the additional value of capacity at peak times. Were these counted as output benefits, MFP growth would have been higher.

Nevertheless, the fact that some pressures have legitimately led to rising capital investment, and therefore a measured fall in productivity, does not necessarily mean that network businesses have performed as efficiently as they could. The regulator and many customers claim that regulatory flaws have led to premature and inefficient investment. These investment patterns (and the possibility of addressing them through benchmarking) are the preoccupation of chapters 5 to 8.

Moreover, even though customers value reliability, it is not clear that many of the investments have actually increased reliability or, to the extent that they have, that the benefits to customers have outweighed the investment costs (and the associated price increases that these entail). Similarly, while rising peak to average demand requires network reinforcement, it is an open question whether other approaches — such as demand management — could have been used as a more efficient alternative. Accordingly, there is a potentially large difference between the *proximate* causes of rising network investment and the real underlying forces at work.

## 2.6 Reliability

The reliability of networks has many dimensions — such as the number of outages per customer, average interruption durations and the geographical reach of outages (chapter 14). Generally, transmission networks are very reliable due to their high level of redundancy (built-in additional, or spare, capacity), and the rarity of events likely to trigger outages. Consequently, the most meaningful measures of network performance over short periods relate to distribution networks.

There are marked differences in reliability levels between states, with a persistent gap between that of Queensland distributors and those in other jurisdictions (figure 2.16), only some of which appears to reflect lower customer densities.[[27]](#footnote-27)

The AER has observed that the reliability levels, as measured by average annual outage durations[[28]](#footnote-28) and the annual number of interruptions per customer[[29]](#footnote-29) have been relatively stable over time. The Commission found only one statistically significant trend — an increase in average minutes of outages per customer of 10 minutes per year in Victoria.

While there is a positive relationship between annual interruption frequency and interruption duration, it is not a strong one (figure 2.16). Since, all things being equal, any reduction in interruption frequency should lead to reductions in average annual hours lost per customer, this implies that average durations of interruptions[[30]](#footnote-30) are tending to rise as interruption rates fall. There are statistically significant (but small) trend increases in average durations per outage in Queensland, Victoria and Tasmania, whose cause is unknown.

Regardless, the reliability data show that many of the shifts from year to year reflect random events — shown by the gyrating movements in figure 2.16. It is certainly not evident that the large increases in capital expenditure across the NEM have yet achieved greater reliability. While this suggests inefficient investment, there may be other confounding factors at work (an issue that benchmarking analysis at the business and sub-regional level might shed light on).

## 2.7 What is at stake?

As shown in tables 2.2 and 2.3 and figure 2.6, the electricity network industry commands a large amount of resources and provides services throughout the economy.

Figure 2.16 Reliability varies significantlya

|  |  |
| --- | --- |
|  |  |
| **Average minutes lost per customer (SAIDI)** | |
|  |  |
| **Average minutes lost per customer (SAIDI)** | |

a The data reflect total outages experienced by distribution customers, including outages resulting from issues in the generation and transmission sectors. In general, the data have not been normalised to exclude outages beyond the network operator’s reasonable control, although problems due to major weather events have been excluded. SAIDI denotes System Average Interruption Duration Index.

*Data source*: AER (2011b, p. 68).

That suggests potentially large benefits from reducing even small inefficiencies, let alone those of the magnitude suggested by some participants. Like unhappy families in Tolstoy’s *Anna Karenina*, inefficiency can be manifested in many ways.

* Businesses may invest prematurely in what would ultimately be productive investment (the likely outcome of insufficient demand management or excessive reliability standards).[[31]](#footnote-31)
* Businesses may use existing capital inefficiently (lower capital productivity). For example, poor maintenance arrangements may require more redundancy than necessary.
* Businesses may make investments that are not required at all to produce output (the conventional definition of ‘goldplating’).
* Investment costs may be excessive due to poor project management.
* Labour may be in excess of what is required or poorly used (resulting in lower labour productivity).
* Physical investments and labour inputs may be at efficient levels, but may be priced excessively. This could arise if the weighted average cost of capital is too high or if unions are able to negotiate higher wages (which appears to be true — figure 2.14 — especially for the state-owned corporations). High network prices lead to so-called allocative efficiency losses for customers (chapter 3). The structure of prices may also be inefficient if they are not cost-reflective (an issue particularly relevant to time-based charging — chapter 11).

The incorporation of benchmarking into incentive regulation (or even the publication of benchmarking results) attempts to eliminate such inefficiencies. However, the magnitude and timing of any such benefits depend on the nature of the policy reform and the source of the inefficiency.

Since most regulatory determinations have some years to go (table 2.5), at best, any reforms of incentive regulations would not have effects on the most costly part of the system (distribution) until after mid‑2015 at the earliest. Reforms to incentive regulations may take some time to deliver benefits. This (and the period taken to roll out smart meters) also extends the timing of major demand management initiatives by some years (chapter 10). The issue of aligning reform to regulatory determinations is discussed further in chapter 21, and especially the risk that slow reform can inordinately delay benefits for consumers.

Table 2.5 Timing of regulatory determinations

|  |  |  |
| --- | --- | --- |
| State | Prior to AER role | Current and future AER determinations |
| Distribution network businesses | | |
| Qld | 1 July 2005 to 30 June 2010  (QCA) | 1 July 2010 to 30 June 2015 1 July 2015 to 30 June 2020a |
| NSW | 1 July 2004 to 30 June 2009  (IPART) | 1 July 2009 to 30 June 2014 1 July 2014 to 30 June 2015b 1 July 2015 to 30 June 2019 |
| Vic | 1 January 2006 to 31 December 2010 (ESCV) | 1 January 2011 to 31 December 2015 1 January 2016 to 30 December 2020a |
| SA | 1 July 2005 to 30 June 2010  (ESCOSA) | 1 July 2010 to 30 June 2015 1 July 2015 to 30 June 2020a |
| Tas | 1 July 2008 to 30 June 2012  (OTTER) | 1 July 2012 to 30 June 2017 1 July 2017 to 30 June 2022 |
| ACT | 1 July 2004 to 30 June 2009  (ICRC) | 1 July 2009 to 30 June 2014 1 July 2014 to 30 June 2015b 1 July 2015 to 30 June 2019 |
| Transmission network businesses | | |
| Qld | 1 January 2002 to 30 June 2007  (ACCC) | 1 July 2007 to 30 June 2012 1 July 2012 to 30 June 2017 1 July 2017 to 30 June 2022 |
| NSW | 1 July 2004 to 30 June 2009  (ACCC) | 1 July 2009 to 30 June 2014 1 July 2014 to 30 June 2015b 1 July 2015 to 30 June 2019 |
| Vic | 1 January 2003 to 31 March 2008  (ACCC) | 1 April 2008 to 31 March 2014 1 April 2014 to 31 March 2017c  1 April 2017 to 31 March 2022 |
| SA | 1 January 2003 to 30 June 2008  (ACCC) | 1 July 2008 to 30 June 2013 1 July 2013 to 30 June 2018 1 July 2018 to 30 June 2023 |
| Tas | 1 January 2004 to 30 June 2009  (ACCC) | 1 July 2009 to 30 June 2014 1 July 2014 to 30 June 2015b 1 July 2015 to 30 June 2019 |

a Preliminary determination with mandatory re-opener. b Placeholder determination under old rules. c Old rules for 3 years.

*Sources*: Various determinations by the AER and by state and territory regulators; AER (2013c)

Even when the AER makes new regulatory determinations, it would not be possible to deploy existing genuinely ‘goldplated’ capital elsewhere — these are sunk investments. The best that can be achieved is a lower future level of investment to avoid goldplating.

The better use of the existing capital stock and improved project management could have more immediate efficiency effects — for example, arising from eliminating some of the constraints on the performance of state-owned network businesses. Given incentive regulations, this would increase network profits, but not reduce prices until the next reset. However, higher profits are better than unnecessary investment. They permit greater investment elsewhere in the economy or can increase consumption.

‘Back-of-the-envelope’ calculations suggest that deferred investment can yield substantial economic benefits. Based on relatively modest assumed deferral (of three years), the net present value of the benefits were around $8 billion over a 30 year period. Whether such savings can be realised depends on how far reliability standards (or other factors affecting the desirable timing of investment) are away from their optimal level.

There could also be large benefits on the employment side. Employable people are footloose in a flexible economy. This means that if there is a productivity improvement in one industry, people usually find jobs elsewhere at close to their former wages. In the case of electricity networks, employment is as geographically dispersed as are the wires and poles. Accordingly, the frictions in movements of employees sometimes associated with employment losses concentrated in a particular location would be less likely. Given estimated employment levels in network businesses, a 10 per cent improvement in labour productivity would release around 2500 workers to other industries, with annual economic benefits of around $300 million. Since these benefits would be sustained over future years, the net present value of the benefits would be substantially greater.

The above estimates of the economic benefits of higher labour and capital productivity are illustrative. They depend on assumptions about future growth in investment, capital and labour and use scenarios that may not be realistic. Nevertheless, one conclusion is robust — small improvements in the efficiency of electricity networks have large absolute benefits for Australians.

Any household consumption-side efficiency benefits from reform are likely to be much smaller as electricity demand is relatively inelastic (section 2.3) and because network infrastructure is only a share of total electricity retail costs. However, the gains may be larger for globally footloose industrial businesses, which will tend to be more responsive to prices and in particular to their likely future trajectory (chapter 3). The consumer transfer benefits from reform would be more important, and as discussed in chapter 3, are still relevant in gauging the beneficial impacts of competition regulations.

### General equilibrium effects

General equilibrium (GE) analysis takes account of the multiple linkages between industries (reflected in the importance of electricity networks to all other industries shown in figure 2.6), and of how price and productivity shocks cascade throughout an economy. GE benefits often exceed the benefits of reform revealed by partial equilibrium analysis (like that above). GE benefits could readily be between 20 and 30 per cent higher.

1. AER (2012q, pp. 64‑7, 79‑81). [↑](#footnote-ref-1)
2. Nameplate capacity refers to the maximum amount of electrical power that can be generated under optimal circumstances. For example, the nameplate capacity of generators using renewable energy — such as those using wind, hydro and solar power — is measured at the highest manageable wind speeds, water flow and sunshine respectively. Accordingly, actual generation capacity may be affected by such things as the operating conditions (or the age of the asset) and hence may differ from nameplate capacity. [↑](#footnote-ref-2)
3. AER (2012q, p. 32) and BREE (2012). [↑](#footnote-ref-3)
4. The market price cap re-calibrated by AEMO annually based on a formula set down in the Rules (clause 3.9.4). [↑](#footnote-ref-4)
5. The story is more complex than this because investors in generators will typically reduce their risks from fluctuating spot prices through derivative contracts. As noted by Frontier Economics, generators usually enter into swap contacts for most of their capacity and so do not benefit from pushing up the spot price for their swap contracted capacity (2010a, p. 13), limiting the gains from strategic behaviour. [↑](#footnote-ref-5)
6. Clause 3.14.2 of the Rules. Unlike the market price cap, the administered cap is not indexed, but can be reviewed from ‘time to time’. [↑](#footnote-ref-6)
7. The Tasmanian Government has responded to a 2012 report issued by an expert panel on the electricity supply industry by announcing full retail competition from 1 January 2014. [↑](#footnote-ref-7)
8. The value of lost load is the amount of money customers would be willing to pay to avoid a disruption to their electricity service. It is generally measured in dollars per unit of electricity. [↑](#footnote-ref-8)
9. Ancillary services maintain key technical characteristics of the system, including standards for frequency, voltage, network loading and system restart processes (AEMO 2010a). AEMO operates eight separate markets for the delivery of frequency control ancillary services (akin to the wholesale energy spot market) and purchases network control ancillary services from transmission businesses and system restart ancillary services under agreements with service providers. [↑](#footnote-ref-9)
10. A consequence explored in a large literature on the economics of integration in electricity and other similar utilities (summarised in Lafontaine and Slade 2007 and Saal 2011). [↑](#footnote-ref-10)
11. See for example, Farsi et al. (2010) and Kwoka (2004). [↑](#footnote-ref-11)
12. Currently, Essential Energy provides some services outside New South Wales, principally in the area around Goondiwindi in Queensland, Victoria and the ACT (Essential Energy, sub. 30, p. 3). There is common ownership (compared with common management) among private network businesses. For example, Cheung Kong Infrastructure and Power Assets Holdings and Spark Infrastructure jointly own Powercor, Citipower, and ETSA Utilities, while Singapore Power International has ownership interests in Jemena, United Energy and ActewAGL and SP AusNet. [↑](#footnote-ref-12)
13. The employment and outputs of the industry are important in gauging the potential economic impacts of reforms (section 2.7). [↑](#footnote-ref-13)
14. ‘Industry value added’ refers to the value of a productive process, after taking into account the inputs into that process from other industries. It is a measure of an industry’s contribution to GDP after accounting for both upstream and downstream industries. The value added by NEM businesses is estimated by applying the 2006‑07 network service share of the value-added of the electricity, gas, water and waste services (EGWWS) industry to EGWWS value added in 2010‑11 (from the ABS National Accounts), and then multiplying by 0.9 to remove non-NEM regions. [↑](#footnote-ref-14)
15. The wage inflation rate was calculated as the weighted average of private and public of the growth rates in labour earnings for the electricity, gas, water and waste services industry (ABS 2012a). [↑](#footnote-ref-15)
16. There are anomalies between the three estimates of electricity consumption made by ESAA (lowest), the Bureau of Resources and Energy Economics (highest) and the AER (the middle). The AER’s measure appears to relate to supply, which must be greater than actual consumption. The ESAA’s data relate directly to consumption by various customers types and likely to be the better measure (derived from ESAA 2012 — tables 3.2 and 3.3). Either way, the AER’s data also suggest falling demand. AEMO’s data (2012a) also shows an estimated decline in customer sales of around 2.4 per cent in 2011‑12, but rising sales by 2013‑14. [↑](#footnote-ref-16)
17. Critical peak demand use (the rare but large spikes in energy use, such as on the hottest days) has also declined in recent years — mostly due to milder weather — but is forecast to rise again (AEMO 2012a and AER 2012q, pp. 29‑30). Regional maximum demand reached new peaks in NSW, South Australia and Tasmania in 2010‑11 (ESAA 2012, p. 16). [↑](#footnote-ref-17)
18. In contrast, the AER (2012q p. 63) identified around 9.7 million customers of distribution networks around the same period (with the difference for the estimates being unclear). [↑](#footnote-ref-18)
19. For example, an industry might be highly dependent on electricity as an input, but have low overall output and low consumption of electricity, and consequently, provide little revenue to network businesses. [↑](#footnote-ref-19)
20. Nevertheless, while lower income households reveal that they have little capacity to substitute away from electricity, there is some (weak) evidence that they are more willing to face power interruptions (chapter 14). [↑](#footnote-ref-20)
21. The reason for the lower price growth is uncertain, but may be due to re-balancing of tariffs (which may also reflect the wider adoption of time-based charging for businesses, which tend to have a less peaky load profile than households — chapters 9‑11). [↑](#footnote-ref-21)
22. This relates to distribution businesses (which account for the bulk of network costs), not transmission businesses. However, the Australian Competition and Consumer Commission (not the AER) had authorised most of the transmission determinations that were in force at the time that prices began to accelerate. [↑](#footnote-ref-22)
23. The AER (2012q, p. 127) derive a slightly different range of 43–52 per cent for 2012, but exclude Victoria (where retail prices are misleading). However, both sources indicate an average network share of around 45 per cent (AER 2012q, p. 5). [↑](#footnote-ref-23)
24. This takes account of the varying typical power consumption patterns across jurisdictions. [↑](#footnote-ref-24)
25. Peak demand in summer between 2012 and 2021 is projected to grow at different rates. The forecast growth rates are low for South Australia, New South Wales and Tasmania, and highest for Victoria and Queensland, (AEMO 2012a). [↑](#footnote-ref-25)
26. MFP measures the extent to which output growth cannot be explained by labour and capital inputs. Over the long-run, it measures greater efficiency and technical progress, while over the short-run it may reflect the business cycle or any other factor that leads to temporary underutilisation of capital or labour. [↑](#footnote-ref-26)
27. Even when controlling for rural location, reliability tends to be lower for Queensland network businesses (AER 2008a, p. 162). [↑](#footnote-ref-27)
28. System Average Interruption Duration Index. [↑](#footnote-ref-28)
29. System Average Interruption Frequency Index. [↑](#footnote-ref-29)
30. This is the Customer Average Interruption Duration Index or the average restoration time. [↑](#footnote-ref-30)
31. In principle, businesses might also underinvest in reliability — though currently this does not appear to be a significant issue. [↑](#footnote-ref-31)