



Australian Government
Productivity Commission

Electricity Network Regulatory Frameworks

Productivity Commission
Draft Report
Volume 2

October 2012

This is a draft report prepared for further public consultation and input. The Commission will finalise its report after these processes have taken place.

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Abbreviations and explanations

Abbreviations

ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
ACT	Australian Competition Tribunal
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AEMA	Australian Energy Market Agreement
CAIDI	Customer average interruption duration index
CAPEX	Capital expenditure
CBA	cost-benefit analysis
CDF	Customer Damage Functions
COAG	Council of Australian Governments
CPI-x	Consumer Price Index minus a benchmark productivity rate (x)
CPP	Critical Peak Price
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DANCE	Dynamic Avoidable Network Cost Evaluation model
DG	Distributed generation
DLC	Direct load control
DM	Demand management
DMEGCIS	Demand Management and Embedded Generation Connection Incentive Scheme
DNSP	Distribution Network Service Provider
DRED	Demand Response Enabling Device

DSP	Demand side participation
ESCOSA	Essential Services Commission of South Australia
ETC	Electricity Transmission Code
EU	European Union
GDP	Gross Domestic Product
HV	High voltage (nominally 5–22kV)
IPART	Independent Pricing and Regulatory Tribunal (NSW)
IRSR	inter-regional settlement residue
kVA	kilovolt ampere
kW	kilowatt
kWh	kilowatt hour
LRMC	Long Run Marginal Cost
LV	Low voltage
MAIFI	Momentary average interruption frequency index
PSCR	Project Specification Consultation Report
MAR	maximum annual revenue
MCE	Ministerial Council on Energy
MDMS	meter data management system
MED	Major event days
MW	megawatt
MVA	megavolt amperes
MWh	megawatt hour
NECF	National Electricity Customer Framework
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company Limited
NEO	National Electricity Objective
NEL	National Electricity Law
NER	National Electricity Rules
NGL	National Gas Law
NMS	network management systems

NTNDP	National Transmission Network Development Plan
NTP	National Transmission Planner
N-x	
Ofgem	Office of Gas and Electricity Markets (UK)
Ofwat	Office of Water Services (UK) (On 1 April 2006, the functions of Ofwat were replaced by the Water Services Regulation Authority)
OPEX	Operating expenditure
PC	Productivity Commission
PV	Photovoltaic
RIT-D	Regulatory Investment Test for Distribution
RIT-T	Regulatory Investment Test for Transmission
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SCER	Standing Council on Energy and Resources
STPIS	Service Target Performance Incentive Scheme
SOC	State-owned corporation
TNSP	Transmission network service provider
TOU	time of use (electricity tariffs)
VCEC	Victorian Competition and Efficiency Commission
VCR	Value of Customer Reliability
WACC	Weighted average cost of capital
WAPC	weighted average price caps

Explanations

Billion	The convention used for a billion is a thousand million (10^9).
Findings	<i>Findings in the body of the report are paragraphs highlighted using italics, as this is.</i>
Recommendations	<i>Recommendations in the body of the report are highlighted using bold italics, as this is.</i>
Requests for further information	<i>Information requests are paragraphs highlighted using italics, as this is.</i>

9 Peak demand and demand management

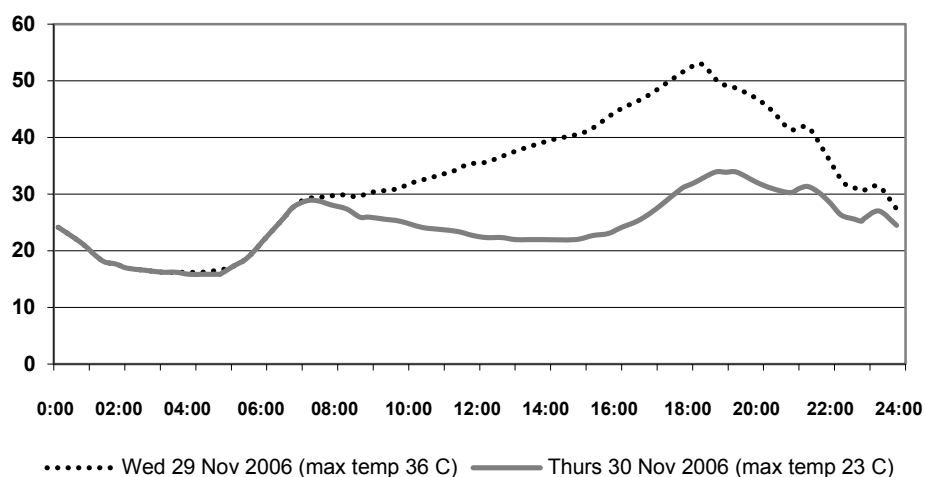
Key points

- Heat waves, cold snaps and other often short-lived and infrequent events can create major spikes in electricity usage, known as ‘peak’ or ‘critical peak’ demand.
- The magnitude of peak demand has risen over the last decade, driven primarily by growth in residential air-conditioning. Other factors, including normal industrial usage, can add to demand during peak periods.
- Peak demand is a key driver of investment in generation and network capacity, the costs of which are ultimately borne by all electricity users.
 - capacity that caters for less than 40 hours a year of electricity consumption (or under one per cent of time) accounts for around 25 per cent of retail electricity bills.
- ‘Demand management’ involves financial incentives or non-price means of curtailing peak demand, including shifting electricity usage to non-peak times.
- Some key commercial electricity users are subject to demand management, but network charges generally fall short of being cost-reflective, with only a small share of businesses facing much higher network charges at peak times.
- Households are not provided with such incentives. Rather, under current ‘average’ network pricing, the substantial additional costs of meeting peak demand are spread across all households and time periods. This smoothing of prices:
 - encourages over-consumption at peak times and inefficient supply-side investment
 - results in electricity bills being higher than necessary over the longer term
 - may create inequities, with low income consumers cross-subsiding the better off.
- By signalling the much higher costs of drawing on system capacity at peak times, demand management approaches can give consumers strong incentives to economise, where feasible, on electricity usage during peak demand periods — and would reduce the cross-subsidisation of ‘peaky’ consumers.
- The adoption of demand management by electricity network businesses appears low. Chief among the possible causes are poor understanding of potential benefits by consumers, that smart meters are not widely available for residential users and that distribution businesses face conflicting incentives.
- If efficiently implemented, critical peak pricing would produce savings worth around \$100-\$250 per household each year (including the costs of smart meters). Consumers could reduce their electricity bills in the short term and slow increases in the longer term.

9.1 What is peak demand and why is it a problem?

Demand for electricity is inherently variable and can fluctuate from hour-to-hour, day-to-day, season-to-season and year-to-year. The causes are numerous and include both random and habitual consumption behaviours, business and sleeping hours, and seasonal and daily changes in outdoor temperatures. As well as the common fluctuations in electricity usage seen through each day and across the year, sometimes there can be major spikes in usage, for example during unusually hot days (figure 9.1).

Figure 9.1 **The impact of temperatures on the profile of daily load**
Queensland, MVA



Data source: Topp and Kulys (2012).

In contrast to the variable nature of electricity demand, network capacity (which is determined by the technical design limits of individual network elements) cannot be increased in the short-run. As network usage approaches or exceeds capacity limits, there may be damage to equipment and loss of network performance, which may even lead to a partial or full system shutdown (AEMC 2008b).

As it is not economic to store electricity at its point of use, avoiding supply failures requires networks to be built to reliably exceed peak demand. That is, they must be able to accommodate the highest draw of power from end users in any instant.

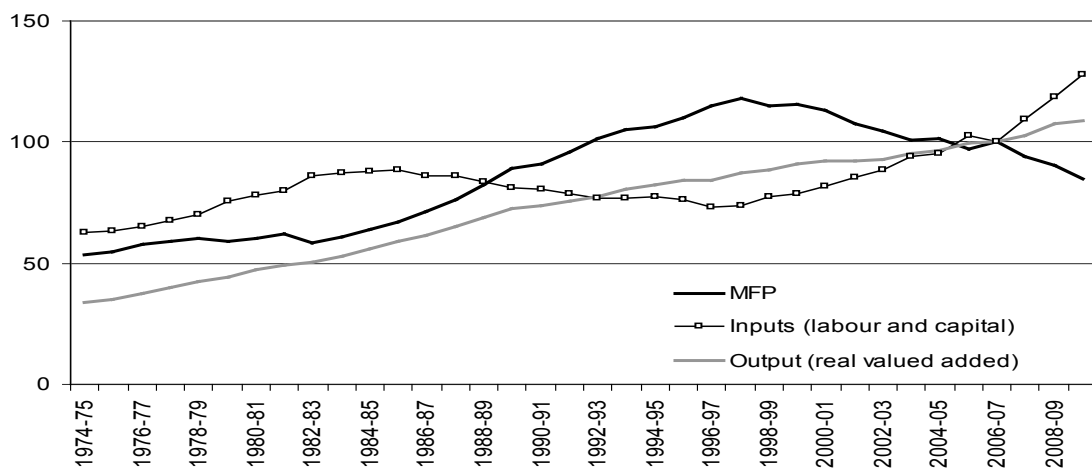
This means that infrequent and short periods of high electricity consumption can require a disproportionate share of generation and network investment, which in turn drive up the cost of electricity generally. This is the problem of ‘peak’ demand (or ‘critical peak’ demand, as the problem of major spikes is sometimes called).

Commentators have used different metrics to demonstrate the scale of the problem. For example:

- \$11 billion in system (network and generation) capacity is used for only 100 hours per year
- capital expenditure to accommodate ‘peak load growth’ in the NEM distribution network accounts for around 45 per cent of approved total expenditures, and slightly more than half of transmission spending (AEMC 2102f)
- around 25 per cent of retail electricity bills reflect the cost system capacity that is used for less than 40 hours a year (or under one per cent of time) (NESI 2011).

In Australia, although the ‘magnitude’¹ of peak demand has dipped slightly with the last two (mild) summers, overall it has been trending upwards over the last decade. To cater for this growth, there has been significant generation and network investment. Yet over the same period, total demand has actually been flat or falling in the NEM. This has caused the utilisation of network assets to decline, contributing to a fall in estimated multifactor productivity (Figure 9.2).

Figure 9.2 Electricity supply: inputs, output and multifactor productivity
Index 2006-07 = 100



Source: Topp and Kulys 2012

¹ The most common way of quantifying the magnitude of peak demand is to compare the maximum quantity of electricity consumed to the average quantity consumed. This measure allows the comparison of peak consumption in different regions and over time. However, to implement effective measures to address peak demand, it is also necessary to have a time dimension. From a consumer’s point of view, they need to know that reducing electricity consumption in a given number of hours per year should slow the growth in future network prices. (In practice, network operators have started to put in place a number of demand management schemes — at this stage, mainly confined to business users — based around ‘critical peak events’.) These critical peak events typically occur for around 40 to 80 hours per year.

Of course, it is not surprising that people demand significantly more power when outside temperatures are particularly warm or cold. Consumers may well value the comfort and amenity gained from their use of network capacity very highly during peaks.

Growth in peak demand therefore need not indicate an economic problem, at least not on its own. Rather, the issue is whether the rate of peak demand is economically efficient, given the benefits and costs entailed. This depends on whether the amenity and other benefits consumers gain from all of their peak electricity consumption are at least commensurate in value with the high cost of supplying it.

Appropriately structured time-based prices that reflect those high costs would help to confirm this. Faced with such price signals, consumers would have a financial incentive to consider reducing or shifting the timing of some or all of their peak electricity use, and suppliers would receive a signal about the value consumers place on additional peak capacity.

However, as discussed in more detail below, little use is currently made of cost-reflective time-based network pricing. Some businesses face price signals that partially reflect supply costs, but this is confined mainly to wholesale energy costs rather than reflecting the costs of peak network capacity.² For most households and many small businesses, average (or flat) network tariffs mean that the substantial additional costs of meeting peak demand are spread across all households and time periods. Consumers thus have little incentive to economise on their usage in these periods, so peak consumption exceeds what would likely be observed were consumers to face its true cost.

The upshot is that, in these circumstances, growth in peak electricity demand is likely to be inducing (or bringing forward) a sizable stream of otherwise unnecessary investment, for which consumers ultimately pay. And the widening gap between peak and average demand is contributing to reduced productivity in the electricity sector.

² With hedging arrangements or contracts with generators, even these pricing signals may be muted.

9.2 A roadmap for how this report addresses peak demand management

This chapter

This chapter is the first of four relevant to the problem of peak demand as a driver of electricity network costs, and appropriate solutions to it. It highlights that, if left unfettered, peak demand and electricity costs would continue to rise inefficiently. It then establishes a rationale for demand management to reduce spending on peak-specific network capacity and limit future increases in electricity bills.

Accordingly, having already outlined why peak demand is a problem (section 9.1), this chapter:

- examines in more detail various facets and causes of the problem (section 9.3)
- explains how the tools of demand management, including both cost-reflective pricing and non-price measures, can potentially address peak demand (section 9.4)
- investigates the extent to which demand management is applied across the NEM (section 9.5)
- outlines reasons for the limited uptake of demand management to date (section 9.6)
- examines estimates of the prospective benefits and costs from the further adoption of demand management in Australia (section 9.7).

The following chapters

Chapters 10, 11 and 12 address barriers to demand management, with the associated recommendations forming a package of interrelated reforms:

- chapter 10 assesses the technologies required to implement demand management, including the need for smart meters to allow time-based pricing and achieve other forms of demand management
- chapter 11 evaluates the role of cost-reflective (time-based) network charges that allow consumers to reveal how much or how little investment in distribution capacity they value. It outlines the importance of a carefully managed transition, along with measures to address equity and affordability concerns and to support distribution business's engagement with retailers and community consultation.
- chapter 12 examines reforms that would be complementary to the transition to time-based pricing including:

-
- the framework for network regulation and the incentives it creates (or currently fails to create) for network businesses to invest in demand management. That includes their motivation to price network services efficiently or employ other demand management solutions
 - the important intermediary role of retailers, including their incentives and flexibility to engage demand management.

Scope of the analysis

The terms of reference for this inquiry are focussed on network expenditure. Accordingly, the Commission's treatment of demand management gives prominence to achieving network efficiencies. Nevertheless, managing peak demand for network services can also lower generation costs. The Commission has taken account of the potential for such benefits in its empirical analysis (section 9.5).

The terms of reference for this inquiry also direct the Commission to have particular regard for the AEMC's current *Power of Choice* Review. The broad scope of that review goes beyond the Productivity Commission's consideration of demand management, which focuses on the potential to limit network expenditure and associated prices. However, to ensure a coherent approach to demand management, in considering the case for reforms the Commission has taken into account the intermediary role of retailers because charges from network businesses are passed on to retailers, but to be effective cost reflective prices need to be passed through to consumers.

Based on the recommendations in the AEMC's *Power of Choice* Draft Report (released in September 2012), the Commission has afforded less attention to a number of initiatives the AEMC has signalled an intention to address as a priority. (For example, the AEMC has suggested changes targeting areas where there is evidence of 'low hanging fruit', including to harness the demand management potential of industrial and large businesses users. The Commission considers early action in these areas would be beneficial, including the application of more efficient network charges to commercial end-users.) Instead, the Commission has focussed on changes that are of a longer term nature focussed on the contribution that households make to peak demand — gradually taking effect over the medium- to long-term. In some of these areas, there are some key differences between the Commission's suggested approach and that of the AEMC. However, as the final recommendations by the AEMC Review are not due to be released until November 2012, they will be addressed more specifically in the Commission's Final Report (April 2013).

9.3 Facets of the peak demand problem

There are several different facets to the peak demand problem. Understanding them and their causes is critical for devising efficient policy solutions.

There are multiple types of peaks

Localised network peaks

Congestion can occur in localised areas within the distribution network. It typically occurs in the evening on hot summer days or in the early morning on very cold days. These peaks in demand, and the congestion which can result, come about because of demand and supply characteristics, including:

- the coincidence of similar end uses, such as the time most people arrive home from work and turn on their air conditioners, or in areas of the network with similar industrial uses
- the limited levels of spare capacity in some areas of the network experiencing increasing congestion and approaching an investment ‘trigger point’ (and, to a lesser extent, the configuration of the network³).

Such peaks most commonly present at the zone substation level of the distribution network, because users with similar demand profiles tend to congregate in a geographical area, often due to local planning restrictions. (A high concentration of similarly ‘peaky’ users in a local network area will result in a network load profile that is far peakier than one that includes a mix of residential, business, commercial and industrial users.) Further, according to Oakley Greenwood:

Because different parts of the network serve different sets of customers, peak demand from the network perspective is essentially a local matter and is based on the area and specific set of customers served by that part of the network. (2012a, p. 23)

Whole of system peaks

As well as localised peaks, ‘whole of system’ energy peaks can occur if demand reaches very high levels across the NEM, or a NEM region. In such instances, energy prices in the wholesale spot market can spike and large transmission lines

³ For example, with some network configurations, it may be possible to shift loads between adjacent substation areas, so that congestion at one substation can be relieved by transferring load to an unconstrained substation.

(including interconnectors) may reach capacity. Some generation capacity only exists to deliver electricity during wholesale market spikes.

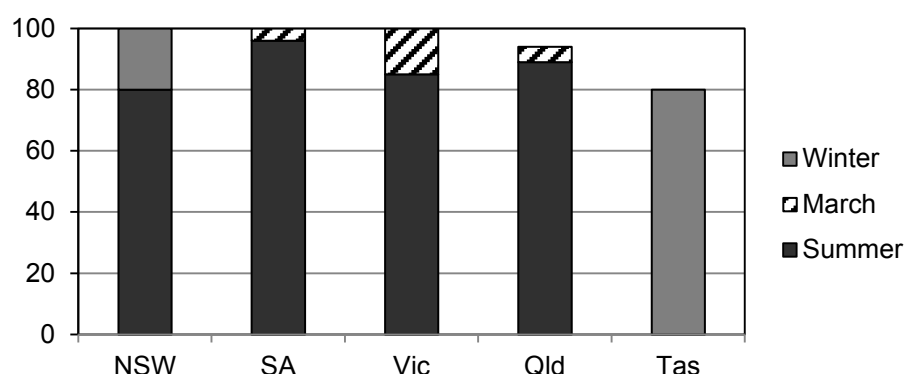
Retailers must also manage the risk of high wholesale pool prices during whole-of-system peaks, which they do through a variety of tools including purchasing various financial derivatives, purchasing supply contracts from generators, or owning generation assets themselves. Each of these approaches is supported by the existence of a ‘natural hedge’ — that is, where price fluctuations result in profits to generators that are perfectly offset by losses to retailers and vice-versa (appendix C). Managing the risks of whole of system peaks, therefore, adds to the cost of retailers supplying energy to their customers.

Many factors can of course contribute to wholesale price spikes. These include intraregional transmission failures, interconnection capacity constraints, generation failures or disorderly bidding. However, as the Australian Financial Markets Association indicated, days with high demand are generally a pre-requisite:

The few days with high maximum prices are associated with periods of high demand with only a very small number of exceptions in the 870 day sample [from January 2009 to May 2011]. Conversely, periods of low demand are unlikely to be associated with prices in excess of \$300/MWh. (AFMA 2011a, p. 3)

In most states in the NEM, demand peaks occur most frequently during summer (figure 9.3). The peaks are caused by the combined electricity use of industry, retail and residential consumers, but tend to occur when large numbers of people experience very hot conditions on normal workdays (Ernst & Young 2011).

Figure 9.3 Seasonal timing of peak demand
Highest 100 half hour periods of energy use in each state between 1999 and 2011



Data source: Ernst & Young 2011

Addressing whole-of-system versus local peaks

Wholesale price peaks will often coincide with local network peaks, but the two can occur independently or may overlap only to a limited extent:

Network peaks most commonly occur in the distribution network, and will not necessarily coincide with peaks in the wholesale spot price for electricity. (NESI 2011, p. 74)

Notwithstanding such unpredictability, it is typical that:

- peaks in wholesale energy demand occur late in the afternoon around 4 pm and include a large proportion of business and major industrial loads
- local network peaks will occur in the early evening, usually between 6-8 pm, and are associated with a higher proportion of residential load.

A demand management solution to address a localised network peak will typically be designed differently from one addressing a whole-of-system peak that causes wholesale prices to spike (though a single technology platform can be used to implement solutions addressing both peaks⁴). Even still, there may be interactions between demand management approaches designed to impact network or wholesale market peaks. As recognised by the AER:

...an initiative targeting reductions in network peak demand could also provide additional benefits to the wholesale market (in terms of the deferral of generation capacity). (AER 2012c, p. 2)

Adapting demand management to the relevant geographic area is particularly important for managing local network peaks, as a threshold reduction in peak demand will be required to defer a capital project and the annual deferral value — the maximum amount a network business would see which might instead be spent on a demand management solution — varies considerably depending on inherent supply costs.⁵ As recognised by the AEMC:

Regional variations in demand quantum and timing, and the regional basis of infrastructure planning decisions, mean that efforts to influence peak demand from a top down, whole of market level may need to be tailored to the local market characteristics. (2012g, p.1)

In contrast, managing whole of system peaks is less contingent on a specific quantum of demand, with all load reduction being of some value.⁶

⁴ Smart meters can allow both distribution businesses and retailers to implement demand management, addressing network and wholesale peaks respectively.

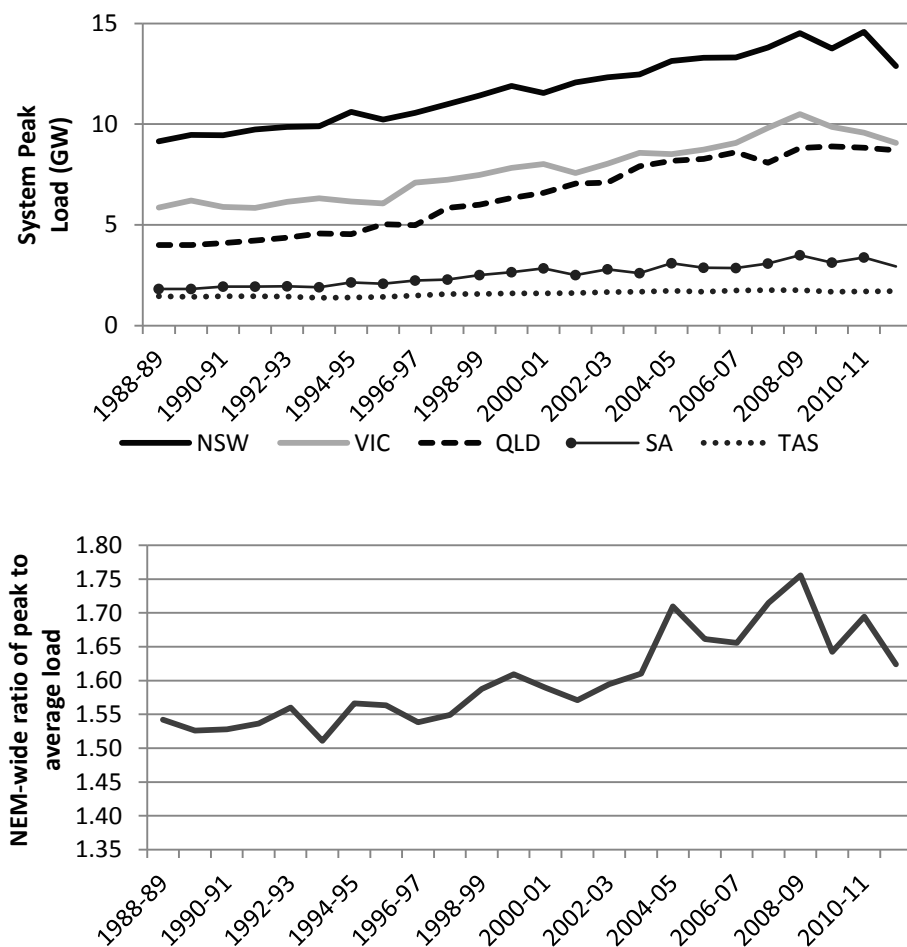
⁵ A large investment (reflecting economies of scale) will have a high annual deferral value.

⁶ An exception is when the security of the NEM is under threat due to an imbalance between available supply capacity and demand at any instant, which can call for shedding of a threshold volume of load to prevent system failure.

Peak demand is growing and becoming more ‘peaky’

While determinants of peak and average demand overlap (box 9.2), since 2007–08 average demand has been flat or falling in the NEM but peak loads have been trending upwards over the longer term (figure 9.4). Thus, the gap between peak and average demand is widening (albeit with some exceptions, generally observed during a run of milder seasons).

Figure 9.4 Rising peak demand and its increasing ‘peakiness’



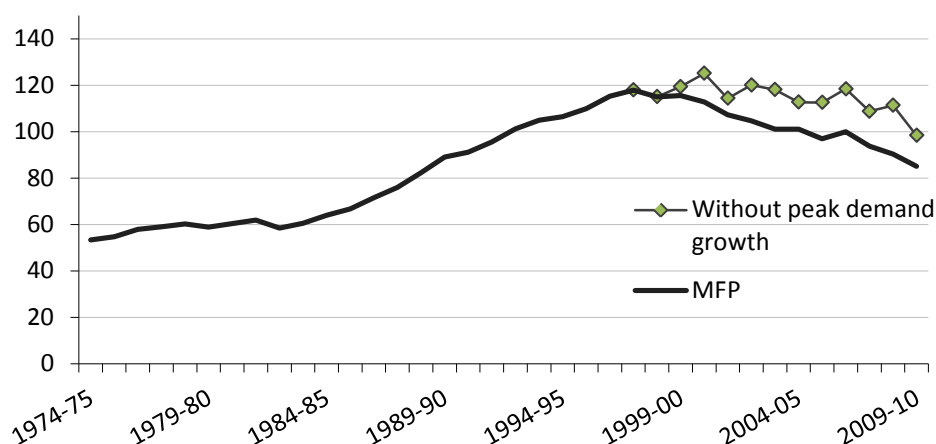
Data sources: ESAA reports various years.

It should be noted that year-to-year variation and short-term shifts in prevailing weather conditions can create ‘noise’ around longer-term trends in peak demand growth. This can complicate the forecasting of peak demand and planning of network augmentation projects to accommodate expectations of growth. Seasonally adjusted estimates attempt to correct for weather driven variation in peak demand in NEM regions.

While long term forecasts of peak demand generally assume continued long-term growth, most regions of the NEM have experienced relatively mild summers in recent years, which have resulted in a lower rate of peak demand growth compared to earlier years (box 9.1). In the absence of policy changes (or structural shifts from technology and appliance changes) affecting the underlying determinants of peak demand, a greater number of future peak events is expected (on average) than has occurred over the last two years.

Because investment in additional capacity is generally forward-looking and ‘lumpy’ (driven by economies of scope and scale, with an expectation of continued growth in demand) the utilisation of network assets typically falls following such investment. In addition, the fall in network utilisation following investment has been compounded by the much flatter (or even falling) growth in average consumption across the NEM. Accordingly, the utilisation of network assets has declined in most states (chapter 6), and therefore has contributed to the decline in measured multifactor productivity (figure 9.5).

Figure 9.5 Peak demand growth reduces productivity
Multifactor productivity index



Data source: Topp and Kulys 2012

The peakiness of demand (that is, the ratio of average to peak demand) significantly affects the cost of supplying electricity. Although the pattern of electricity use across households varies widely, household consumption is generally much ‘peakier’ than business, large commercial and industrial uses. As an indication of the long term gains attainable from improving the load factor,⁷ it is estimated that moving from a 38 per cent to a 50 per cent load factor would reduce an average

⁷ The ratio of average to peak electricity consumption, or the ‘peakiness’ of consumption

electricity bill in 2015 by \$32 per MW. This is equivalent to about \$1.6 billion per annum across the NEM (Simshauser 2012).

Box 9.1 The cyclical impact of climate muddies the long term trend

Peak electricity demand in Australia is most commonly experienced on very hot days. In the last two years, there was a decline in the frequency of very hot days. A recent publication by climate scientists can provide some longer term context to these recent weather events. In the most recent state of the climate report, the CSIRO and the Bureau of Meteorology (2012) said:

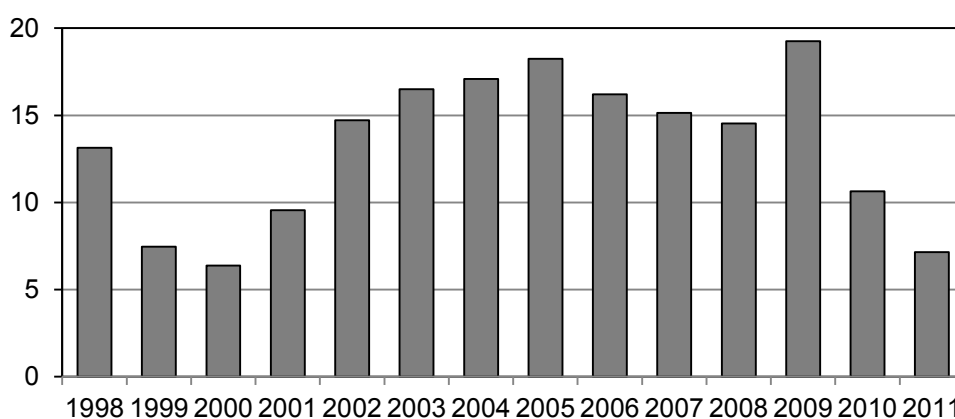
Australian annual-average daily mean temperatures showed little change from 1910 to 1950 but have progressively warmed since, increasing by 0.9°C from 1910 to 2011 ...

The warming trend has occurred against a backdrop of natural, year-to-year climate variability. Most notably, El Nino and La Nina events during the past century have continued to produce the hot droughts and cooler wet periods for which Australia is well known. 2010 and 2011, for example, were the coolest years recorded since 2001 due to two consecutive La Nina events. (p. 3)

In the eight years prior to those La Niña events, the average number of days where the maximum temperature exceeded 40 degrees Celsius (averaged across reporting weather stations throughout Australia) exceeded 14, compared to less than 11 days in 2010 and less than 7 days in 2011.

Australia's seasonal climate is inherently variable

Average number of days over 40°C



The recent decline in the number of very hot days is not evidence of an end to the long run warming trend (BOM 2012). Instead, it follows similar patterns to most other La Niña events (such as that in 1999 and 2000), highlighting the substantial impact that climate variation has on weather events in different years. As such, the frequency of very hot days is projected to increase in the future.

Source(s): BOM 2012; CSIRO and BOM 2012

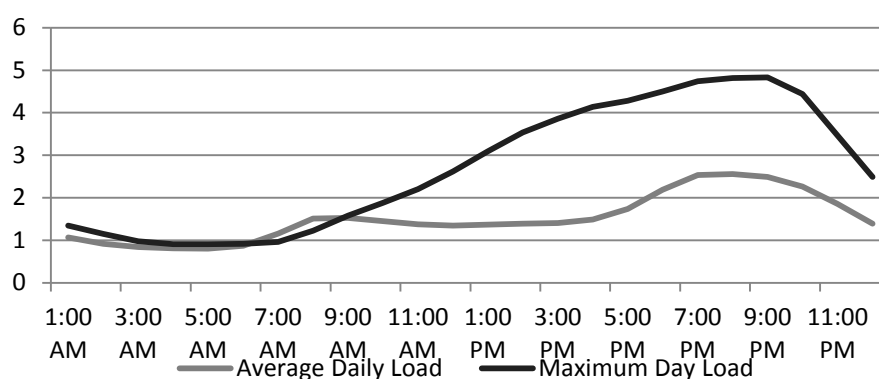
Household usage is a major contributor to peak demand

Household consumption accounts for less than one-third of total electricity use but has important implications for peak demand, with some estimates showing it may account for more than two-thirds of peak loads (NERA 2008a). Of course, the contribution to peak load at a given network asset may be much higher or lower than this, depending on the proportion of household users within localised areas of the network (compared to commercial and industrial users). For example:

- the Commission has been told that, for some zone substations, 80 per cent or more of the customers will be residential
- even if the share of residential load to other uses is 50:50 at other substations, during peak times, residential load will generally make up a higher proportion of the load.

When residential demand peaks, the load on the network will typically be about double that experienced on an average day around the same time (figure 9.6).

Figure 9.6 Household peak loads are very peaky
Household electricity demand (kW), by time of day



^a Based on interval meter data from 3000 Sydney households in the financial year 2010.

Data source: AGL 2012, Presentation to AEMC PoC Review, Sydney April.

Factors that affect household electricity use during peak periods may include consumers' income⁸, the types of electrical appliances they own and the pattern of use, lifestyle factors and weather events. These factors also change over time, such as from the increasing penetration of solar panels and a range of government-initiated energy efficiency programs (although each of these factors has primarily affected average demand, with a lesser effect on peak consumption).

⁸ The particular effect of rising income on the rate of peak demand growth is described as a paradox, since the associated increases in electricity costs may actually cause 'fuel poverty' (Simshauser and Nelson 2012).

Box 9.2 **Determinants and forecasts of demand**

The growth of peak (maximum) electricity demand reflects prices and a variety of economic, policy and structural determinants. Apart from electricity pricing levels and structures, relevant factors underlying growth rates include:

- economic prosperity and both the penetration of household air conditioning to address seasonal temperature variability, and the size and design of houses (especially the trend to two story houses with no eaves)
- the penetration of rooftop photovoltaic systems, which can reduce electricity drawn from the network and centralised generation sources
- broader economic conditions, both domestically and internationally, and population growth driving new connections
- the outlook for large industrial uses and specific sectors, such as mining and manufacturing
- policy settings, including energy efficiency initiatives.

Although peak and average demand have many of the above determinants in common, their rates of growth will not always move in tandem or at the same rate.

Growth in peak (maximum) demand is forecast to be lower than in previous years, but is projected to continue to grow in the longer term (AEMO 2012a). Over the next 10 years, annual growth in peak demand across NEM regions is forecast to range between 1-2.5 per cent. These forecasts are revisions on previous estimates, such as in the annual Electricity Statement of Opportunities (AEMO 2011b), which predicted annual growth rates in excess of 4 per cent in some regions over the next ten years.

Annual energy (or average) consumption is projected to be 2.4 per cent lower in 2011-12 than 2010-11, and over the next ten year period, average annual growth is forecast to be 1.7 per cent (AEMO 2012a). Power prices and economic conditions principally underpin average demand growth, although other determinants of industry performance such as the level of the Australian dollar will also affect the derived demand for electricity.

In response to recent increases in network and energy prices, total household (and business) consumption has displayed a ‘conservation effect’ — that is, average consumption has decreased as consumers seek to limit their bills (AEMO 2012a). Survey evidence indicates that 92 per cent of households have taken steps to limit their power use and conserve energy following recent price rises (or for other, largely environmental, reasons) (ABS 4102, 2010). Higher prices will also encourage some reduction in consumption during peak demand periods. However, if consumers faced the same weather conditions, it would be expected that the reduction in peak consumption would be proportionately less as consumers generally find it less convenient to reduce electricity use during peak times.

Peak demand growth would be more explicitly affected in cases where demand management tools discourage peak consumption. This could include critical peak pricing (higher prices during periods of peak demand) or consumers agreeing to have some of their electricity use curtailed — such as through direct load control schemes.

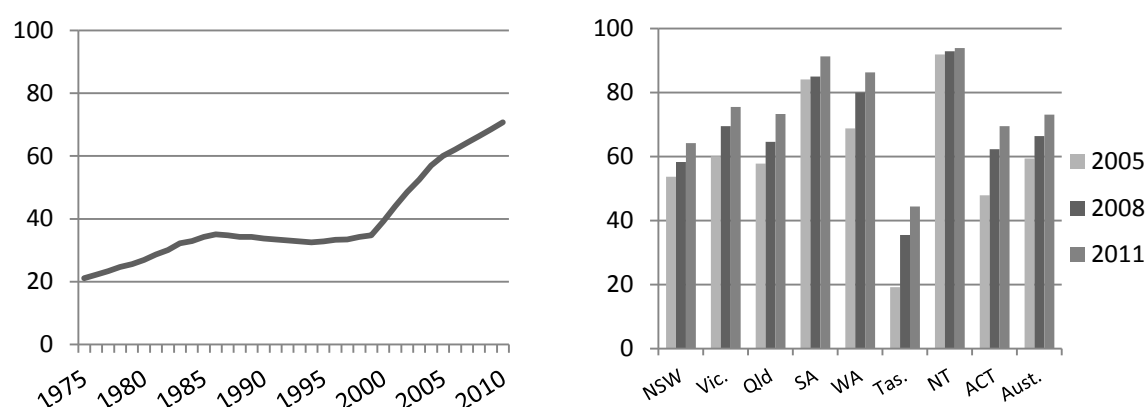
Currently though, even where metering would allow higher peak-time charges for residential users, the network component of these charges only vaguely reflect underlying costs (including simple and predictable shoulder, off peak and peak charges⁹). As such, peak demand (typically confined to the handful of days each year) has been minimally affected.

Residential air-conditioning is the main contributor

According to the AEMC:

The increasing penetration of air conditioning, particularly in the residential sector, has been cited by network businesses as a key reason for increasing maximum demand. (2011a, p.10)

Figure 9.7 The increase in household air-conditioning
Per cent of households with air-conditioning



Data source: Topp and Kulys 2012, ABS 2011

In 2020, the national stock of air-conditioning is forecast to be almost double its year 2000 level (AEMC PoC Review), and the associated use of electricity is projected to be five times greater than it was in 1990 (DEWHA 2008). Rising incomes and the declining cost of air-conditioners are key causes of this trend. Other factors include

⁹ In this chapter, ‘time of use’ charging schemes, refer to where consumers are charged a higher price for electricity consumed for fixed periods every week day — not just during peak demand periods.

new homes that are much larger than in the past¹⁰ and the increasing use of multiple air-conditioners and multi-systems (particularly by higher income households).

The age of air-conditioners and the way they are used can also significantly impact on their contribution to peak demand and, in turn, network costs.¹¹ In most climates, air-conditioning is used for a low proportion of the time — typically for the hottest parts of hot days. As such, they draw significant amounts of energy during peak demand periods, but little or no energy for most of the year, resulting in a very low load factor (ratio of average to maximum consumption). For example, residential air conditioning accounts for 20 per cent of annual electricity consumption, but can account for the majority of the increased residential load during a peak demand event.

Most other household appliances (such as refrigeration) have a much flatter load profile, with a load factor of around 60 to 70 per cent — hence, contributing less to the peak demand problem. Similarly, industrial and commercial uses of electricity also have much flatter load profiles (LaCommare et al. 2002).

Some 56 per cent of households cite that their main reason for using an air-conditioner is (or would be) to sleep better (Galaxy Research 2012). On the basis that overnight use would be unlikely to contribute to peak demand, it would not be as costly to service such demand and, if network prices reflected that cost, consumers could even increase their comfort level more than they might otherwise have chosen. This highlights that it is the use of the appliance (including the timing of use and resulting load factor), rather than the appliance itself, that is the key determinant of its contribution to peak demand.

Given its impact on network investment and the potential to encourage behavioural change in its use, air-conditioning:

... attracts considerable political and policy attention due to its very poor load factor and the potential to create major problems for the electricity generation, transmission and distribution systems on peak summer days. (DEWHA 2008, p.x)

As an indication of the costs of expanding the network to accommodate peak loads from air-conditioning, it is estimated that a 2 kilowatt (electrical input) reverse cycle air conditioner could impose a system wide cost of around \$7000 (DRET 2011).¹²

¹⁰ The new houses in 2005 had double the floor space of an average home in 1986 (DEWHA 2008).

¹¹ There is no comprehensive data on the vintage of the current stock of air-conditioners but, based on survey samples, the average age may be around 6 years (Galaxy research 2012). The type of appliance is also relevant. Most households operate split-system (non-ducted) reverse cycle types, with a low energy efficiency (Sustainability Victoria 2010). Only 20 per cent of new air-conditioning sales are more energy efficient evaporative systems, although these are not suited to all climates.

¹² The \$7000 cost is derived from Energex estimates in the Queensland Energy Management Plan (2011, p. 4) and includes \$4000 in distribution, \$1400 in transmission, and \$1600 in generation costs.

While this estimate illustrates the high costs of investing in incremental units of network and generation capacity, in the Commission's view, it is likely to overstate the actual cost of air-conditioning, since:

- it assumes an extra air-conditioner will require additional generation, transmission and distribution capacity to be built (more realistically it will *contribute to* the threshold decision to expand capacity)
- it assumes that the appliance is always operating during peak demand periods — about 30-35 per cent are normally turned off (Swift 2005; CRA 2006)
- it assumes that all air-conditioners are running at full capacity when operating during peak consumption — a more realistic figure may be 80-90 per cent.

Nevertheless, even if the true cost of an air-conditioner that is used mostly during peak times is more realistically \$2400, that represents an implicit subsidy of around \$330 per year from customers that do not own or do not use air-conditioners at peak times.

Reasons and scope for change

The flat network tariffs currently in place hide the costs of supplying additional peak capacity to meet the increased use of air-conditioning, and therefore provide consumers no financial incentive to change their consumption behaviour. The upshot is that people who own air-conditioners (and use the appliance intensively at peak times) are subsidised by those that do not.

As well as this giving rise to inefficiency, it affects distributional outcomes, since lower income households tend not to own (or own fewer) air-conditioners. ABS surveys indicate that higher income households generally have a higher rate of air conditioning (one or more air conditioners), compared to lower income households. Further, there is some evidence to show that expectations of thermal comfort increase with income and the thermal efficiency of dwellings (the likelihood of which increases with income) (ABS 2010 and 2009).

More recently, the growth in the number of households with air-conditioning has started to slow and may even be reaching saturation in some areas. Nevertheless, the number of months of the year air-conditioning is used is increasing over time — one-third of households used their air-conditioner for 3 to 6 months of the year in 2008, up from a quarter of households in 2002. Further, there is no sign that the increasing use of multiple air-conditioners and multi-split systems will cease in the near term.

While growth in peak demand from the increased penetration of household air-conditioning is a dilemma for network businesses, it does not automatically mean

that targeting their use will provide the most effective solution. When demand is at its maximum, any source of demand reduction can potentially relieve network congestion. As stated by CRA, in evaluating feasible demand management options:

... [demand management] does not need to come from an end use that is causing peak demand to grow. Rather, any end-use load that can be reliably reduced when the network area experiences a peak is useful ... (2004, p.14)

However, demand management trials generally show residential customers with air conditioners activated on very hot days are most flexible about reducing their peak consumption (Futura 2011). Further, in many localised network areas, there would be limited scope to substitute reductions in peak demand use between residential and business users, especially in network areas where household peaks in demand occur much earlier or later than usual business hours (figure 9.7). This means it is important that any solutions consider incentives for households to economise on peak power use. Ideally, to yield network savings, any incentives should target both the specific times network congestion is experienced and households whose load reduction would help to relieve such congestion.

9.4 What is demand management and how can it provide a solution?

Demand management¹³ offers a potential solution to the problem of peak demand by providing incentives for consumers and businesses to reduce consumption at costly peak times and, where possible, shift the timing of their power use to non-peak times.

Potential benefits of demand management

The economic potential for demand management arises because it can:

- avoid an inefficiently high rate of peak demand growth, delaying the need for network augmentation and reducing the size of peak-specific network investments
- improve the utilisation (and productivity) of supply side capacity by allowing financial incentives to shift the timing of electricity use and reduce the gap between average and peak consumption — achieving allocative efficiency
- decrease investment in costly peak-generation and reduce generation costs by reducing reliance on higher cost peaking supply (open cycle gas turbines)

¹³ The literature does not adopt a consistent nomenclature. For the purposes of this chapter, demand side management is used interchangeably with demand response, but generally excludes energy efficiency and energy conservation programs (that tend not to be ‘peak’ focused).

-
- improve competition and reduce the ability of an individual generator to exercise market power in the wholesale market during congestion at peak periods (Joskow et al. 2011; Borenstein 2005; Bushnell 2005; Borenstein and Holland 2005)
 - improve supply reliability, including increasing load shedding options and assisting with the restoration of power after loss
 - reduce volatility in demand (and wholesale prices)
 - allow operational efficiencies for network businesses, including from advanced metering infrastructure, which enables remote access to consumption data, assists with more timely and less costly disconnection and reconnection, and improves network planning and detection of outages
 - in the short term, provide scope for some consumers to receive reduced electricity bills and, in the longer term, could slow the rate of growth of future electricity bills for all consumers.

The focus of this report is on the potential for demand management to delay the large capital cost of expanding supply-side capacity and to improve the overall efficiency of network infrastructure. An investment that is too early or too large¹⁴ will not be productive, especially if it is used very rarely *and* consumers would not gain sufficient benefit to justify the cost of the additional capacity. Importantly, as noted earlier, reducing peak demand and associated supply side investments is not itself an objective, with reductions in peak consumption only desirable to the extent that the costs of peak consumption exceed end users' valuation of it. However, allowing consumers to reveal their preferences can avoid an *inefficient* rate of peak demand growth and, in turn, improve network utilisation.¹⁵

Demand management options

Options to implement demand management are broad and can include a combination of more cost-reflective pricing, negotiated load management programs and distributed generation solutions (chapter 13) (table 9.1). Such measures can also be combined with information-led behavioural change. Some measures will be more

¹⁴ Stemming the rate of peak demand growth can delay the timing of a network augmentation (increase in capacity). Further, for some less 'lumpy' assets (where scale economies are a less significant driver of costs), a lower rate of peak demand growth can also reduce the size of the investment, particularly in less densely populated rural and remote areas.

¹⁵ The extent of many of the other benefits listed is uncertain and would be difficult to quantify with precision. Further, some would be secondary to the thrust of policy and regulatory changes covered in this report. For example, demand management measures targeting network peaks could incidentally improve generation market outcomes.

effective at targeting peak consumption than others, and each will involve different costs to implement. For example, many energy efficiency measures have a ‘conservation effect’ by reducing consumption across all periods, rather than just ‘clipping the peak’ or shifting load.¹⁶

Table 9.1 Summary of demand management approaches

<i>Name</i>	<i>How it works</i>	<i>Technologies involved</i>
Cost-reflective pricing	Charging customers different amounts for their consumption at different times of the day or year, reflecting the varying costs of delivering electricity at different times of year. These price signals could shift consumption away from the peak.	Advanced/smart meters and associated infrastructure and billing systems. Information and control tools can assist consumers to respond. For example, in-home displays and whole house gateway systems can allow appliances to be individually controlled and automatically adjusted in response to prices. Web portals, SMS and email technologies can notify customers in advance of high prices and load control events.
Residential direct load control programs	Networks, retailers (with the agreement of customers) or customers automating the response of household appliances such as air conditioners during network or wholesale ‘peak’ events.	‘Demand response enabling devices’ (DREDs) and communications infrastructure to interact with them. The ‘enabling device’ can include a smart meter.
Industrial and commercial load management contracts	During ‘peak events’ and subject to pre-agreed terms, industrial or commercial equipment is turned down or off by a network or retailer, or an aggregator working on their behalf. Usually the user can opt out at some cost (based on pre-agreed terms).	A variety of options, from manual responses via emails and SMS, to automated responses with the use of ‘Building Management Systems’, ‘Supervisory Control And Data Acquisition’ systems, ‘Site Servers’ and ‘Network Operation Centres’. ^a
Distributed generation (chapter 13)	The production of electricity close to its point of consumption, such that it does not need to pass through all or any of the network. A variant on this is ‘fuel substitution’, in which customers are switched from electric to gas appliances.	Gas co-generation, gas tri-generation, standby generators, gas heating and solar PV.
Energy efficiency	Lowering the electricity demands of appliances, including during peak events.	Wide ranging. Many approaches do not have a targeted impact during peak events.

^a EnerNOC (Correspondence)

¹⁶ For the purpose of reducing peak consumption, the cost of implementing energy efficiency options will typically outweigh the network savings. Nevertheless, some energy efficiency measures can assist consumers to shift the timing of their electricity use — for example, the insulation of dwellings can allow cool air to be ‘stored’ prior to a peak period of consumption.

Consumers respond to price signals

A potentially key tool of demand management is the use of electricity prices that vary to reflect the costs of supply at different times. In principle, such approaches should help ensure that peak network capacity is available for high value uses, in part by allowing cheaper non-peak prices for lower value or less time sensitive uses. Of course, price signals already play a key role in people's decisions about what, when and how much to consume of many different goods and services, and they are also used to ration scarce capacity in some network industries. Thus, differences in airfares will often influence not just which airline but also which flights travellers choose; while in previous times, cheaper rates after 9pm encouraged many people to delay their (then expensive) long distance telephone calls. Although not used extensively to date in Australia to manage electricity demand to households, price signalling appears to the Commission to offer significant scope to do so.

However, since the implementation of time-based network pricing in the electricity market would not be costless and would be a significant change for most consumers, it is sensible to assess the empirical evidence about the performance of pricing approaches in electricity, and in particular to what extent consumers respond to price signals.

Most studies find that Australian consumers do adjust their consumption in response to time-based pricing. For example, across seven Australian pricing trials, the average reductions in peak demand were between 13–40 per cent (Futura 2011). The extent of response by consumers of course depends on the strength of the price signal and consumers' ability to adapt. In particular, when prices are considerably higher during a declared peak event — so-called critical peak pricing — the reduction in peak consumption is generally more than four times that under flatter 'time of use' tariffs (ESAA sub. 23, p. 29; Faruqui et al. 2012; Futura 2011; ESAA sub.23). (Further empirical evidence on consumer's price responsiveness, and flexibility with the timing of their electricity use, is summarised in box 9.3.)

Pricing on its own may not be enough to support an efficient consumption response — a point made by the Standing Council on Energy and Resources:

Many consumers have limited knowledge of and engagement with their electricity consumption and may not understand the new pricing structures sufficiently well to take advantage of new opportunities. (2011a, p. 16)

Box 9.3 **Consumption responsiveness to time-based prices¹⁷**

Findings of studies examining households' responses to time-based electricity pricing include:

- consumers primarily shift power from peak to non-peak times, but total demand also falls (the 'conservation effect'), although usually by no more than 10 per cent (Simshauser 2012)
- the more extreme the climate in a particular region (either hot or cold), the greater the responsiveness
- households with air-conditioners are consistently more responsive at peak times than those without. Moreover, houses with air-conditioning usually demonstrate a capacity to shift their load into non-peak periods, rather than only reduce their total consumption (CRA 2005; NERA 2008b; Futura 2009)
- households are generally less responsive to high peak charges during winter, which is relevant to some New South Wales regions and Tasmania, where winter peaks are higher than summer peaks
- although consumers will normally continue to show some responsiveness to successive price increases during peak events, the incremental response tends to tail off (Borenstein et al. 2011; Caves, Christensen and Herriges, 1984; Faruqui and Palmer 2012; Simshauser 2012; Faruqui and Sergici 2010). Such a result is consistent with increasingly fewer discretionary uses being available as consumers curtail their load in response to higher and higher prices. As an extreme example, the Ausgrid Strategic Pricing Study found no greater response among customers facing a peak to off-peak price ratio of 31, over those facing a 13 fold ratio¹⁸
 - However, some customers facing the higher price did not have in home displays, unlike all consumers facing the lower price (Futura 2011).
- the addition of technology to automatically turn off, turn down or cycle appliances, or notify homeowners of critical peaks and other price information, increases the average response (Faruqui and Palmer 2012). For example:
 - notifying customers (usually 24 hours) in advance of a critical peak event (such as through email, SMS, web portal, or using an in-home display) assists consumers to prepare to shift their load, maintain their comfort and reduce the possibility for inconvenience
 - in the absence of price signals, assistive technologies and information about energy use generally has little impact (Ausgrid strategic pricing study and California state-wide pricing project).

¹⁷ The price responsiveness of commercial and industrial use varies widely, largely driven by production characteristics of the business and the contribution of electricity to business costs.

¹⁸ Not all trials find a declining marginal response as prices increase. For example, the Illinois Energy-Smart Pricing Plan found a price elasticity of -0.047 when the price was below \$0.13/kWh, but -0.082 when it was above (Summit Blue Consulting 2006).

Nevertheless, as discussed in box 9.4, imperfect information, along with cognitive and behavioural traits among consumers, do not preclude the use of pricing to manage demand, although they may have implications for how such pricing is introduced and the role of complementary reforms.

For example, with the agreement of customers, tools to assist consumers to reduce their consumption during peak hours and to take advantage of lower prices at all other times may complement demand management. Tools could include:

- technologies and devices to communicate consumption and pricing information to consumers, which allow them to modify their behaviour to achieve energy savings
- access to demand management services and programs (such as those provided by retailers or other third parties). For example, a customer may choose to participate in direct load control of appliances to ensure that lapses in their monitoring of prices or appliance usage would not expose them to high bills
- access to education on options to change consumption habits.

Acceptance of new pricing arrangements can be encouraged by educating consumers about the real costs of peak-time consumption. People may be willing to change their behaviour if they are aware of the broader benefits of curtailing peak demands. Few people realise the real costs of supplying power for just a few hours of peak demand.

... but 'peaky' consumers will not volunteer to pay

Network benefits will only be realised if a sufficient number of consumers are influenced to adapt the pattern and timing of their electricity use, or to pay the true cost-reflective price for their consumption during peak times. As such, the scale of demand management is therefore particularly important. Allowing consumers to 'volunteer' to face the true costs of their consumption results not only in low uptake, but also in a low level of consumption response.

The efficiencies from demand management come from behavioural change. Inevitably, they are greatest when more peaky users are exposed to the true costs of their consumption habits — an outcome they would be unlikely to voluntarily choose as, at least initially, they could face higher bills (unless they immediately adjusted their consumption patterns).

Box 9.4 Behavioural traits would not preclude cost-reflective pricing

While price signals guide many aspects of consumption and production in advanced Western economies such as Australia, it is sometimes asserted in debates about electricity market reform that consumers either wouldn't or couldn't respond to time-based tariffs and adapt the timing of their power use. To the extent elaborated on, these arguments rest on the perceived pervasiveness and effects of cognitive limitations and behavioral biases among consumers, including:

- the suggested limited capacity of consumers to digest pricing information
- 'status quo' bias related to the familiarity of consumers with flat price structures
- consumer preferences for certainty and valuing loss aversion more than seeking opportunities for savings
- consumer time preferences, including a bias against immediate costs even if these may be outweighed by future benefits. (For example, smart meters represent an immediate cost, while savings from reduced supply-side capacity are realised in the medium to long term.). (Ofgem 2011)

The Commission has examined issues around cognitive limitations and behavioural biases in a number of settings (for example, IC 1996; PC 1999, 2008, 2010, 2012a). Many if not all consumers exhibit some of these traits, which may have implications for appropriate implementation of demand management initiatives such as time-based pricing.

However, the Commission does not consider that they would preclude adaption to time-based pricing by most consumers. Consumers already interact with various forms of dynamic or time-based pricing. That includes purchasing airline tickets, renting cars, parking in a major city, purchasing seasonal vegetables, and driving across Sydney Harbour Bridge.

Moreover, for time-based pricing to be effective does not require that all consumers adjust their behaviour. For example, for some consumers, an apparent disinterest in new forms of pricing is likely to reflect that electricity is a relatively low share of their budget. Some of these consumers may well be willing to 'tolerate' higher prices than undertake the effort needed to reduce their consumption. For many households, including many of those on low incomes for which the cost of electricity is a significantly higher proportion of their overall expenditure, the opportunity to save money by shifting the timing of their consumption (and no longer cross subsidise the peaky use of other consumers) might be an attractive proposition.

Those consumers who are initially worse off due to being exposed to the real costs of their consumption patterns would have an option (and incentive) to shift the timing of their use and take advantage of much cheaper non-peak prices. Importantly, given the

direction of cross-subsidisation across consumers, more cost reflective pricing would be likely to benefit many lower income consumers.¹⁹

Given the above principles, broader application of time-based cost-reflective network pricing is central to informing consumers about the actual costs arising from their consumption patterns, and the benefits of changing those patterns, including motivating their participation in load control options. In its absence, individual consumers have limited choice about ways to lower their electricity bills, apart from reducing overall demand, which does not help reduce peak demand. Although not all consumers would immediately embrace time-based network pricing, most parties, including the AER, accept these principles:

The AER considers effective price signalling to be a necessary feature of any market that seeks to enable behavioural change by empowering participants to make efficient decisions. Further, by making visible the true value of the costs of energy, they provide a mechanism for participants to obtain benefits from facilitating peak demand reductions, and negotiate in an informed manner. (2012, p. 3 sub to PoC Review)

9.5 Demand management is not widely implemented

Current prices are inefficient

Although demand management offers significant scope to address the peak load problem, at present it is not widely implemented. Rather, in contrast to most markets, in which consumers bear the costs of their consumption, in the electricity market, the substantial additional costs of meeting peak demand are not recovered from consumption at peak times.

Most households face inefficient prices

For most residential users, the network tariff charged to their retailer by the distributor comprises a fixed component (an access charge) and a (usually flat) price per unit of consumption (box 9.5). Irrespective of the cost of supplying network capacity at different times, the consumption-based charges are either an average (flat) price or an increasing price for consumption blocks. Such smoothing (or complete flattening) of prices encourages over-consumption at peak times (and under-consumption at non-peak times), drives inefficient supply side investment to meet that consumption, and results in network prices being higher on average than they need to be over the longer term.

¹⁹ Studies of time dependent pricing generally find that low income groups are no worse off, and usually tend to be better off (AEMC 2012d, Deloitte 2012a).

Box 9.5 What costs are included in the price of electricity?

The price of electricity that is visible to an end-user incorporates charges for:

- network services including metering
- energy and risk management costs from the wholesale electricity (contracts) market
- a retail margin, including for billing services.

An electricity retailer recovers all of these charges from end-users and, depending on customer preferences and market (and regulatory) outcomes, they may smooth some (or all) of the variability in these charges on a customer's behalf.

Network costs are passed from a distributor to an end-user's retailer. Since most transmission and distribution businesses apply network charges that are flat (do not vary with time), retailers simply pass-through these costs in a time invariant manner to their customers.

Welfare losses from flat pricing have long been identified, with economist Marcel Boiteux referencing the peak load problem from inefficient flat tariffs in 1949. However, the legacy of traditional accumulation meters to measure electricity consumption for most households has meant that such inefficient pricing has largely been unavoidable. To avoid this, meters must measure consumption on a near real time basis. And, as discussed in chapter 10, while the enabling technology — a smart meter²⁰ — is available in much of Victoria, policy decisions have so far prevented their use for efficient pricing.

In other states, a relatively small number of households now have more sophisticated metering installed and many of these customers face (untargeted) 'time-of-use' network tariffs. (For example, Ausgrid anticipates 400 000 residential users will face a Time-of-Use (TOU) network tariff by mid-2013.) However, the structure of the tariff is likely to have only a minimal impact on peak consumption (figure 9.10), as 'peak' periods are usually set as a routine six to seven hour window mainly in the afternoon and evening of weekdays,²¹ which does not reflect the relatively few hours (say 40 hours) each year when network capacity is most stretched.

Trials of more cost-reflective pricing structures have been undertaken by most network businesses, including of critical peak prices. Electricity reductions during these peak demand trials have typically ranged from 15 to 40 per cent.

²⁰ Such meters can usually communicate prices in half hourly consumption intervals, although in practice consumers could probably not efficiently respond to that frequency of price movements.

²¹ Sometimes defined over a 15 hour period of each weekday.

Prices for businesses capture (some) wholesale energy price variation, but rarely reflect peak network costs

Nearly all large commercial premises have a smart meter installed to enable time-based pricing. Despite this, network charges generally fall short of being cost-reflective, with only a small share of businesses facing much higher charges at peak times.

While the cost-reflective (time-based) pricing of network use for business customers is weak overall, an exception is the critical peak pricing recently adopted by Victorian distributor, SP-Ausnet. SP-Ausnet's business customers have faced such tariffs since 2010-11, which apply to a 4 hour window on no more than five declared critical event days. During these short times, prices have been increased by up to 10 fold (compared to a general flat tariff), and it is estimated up to 25 per cent of the peak demand that would otherwise have been consumed by this group of customers has been curtailed (Futura 2011). However, the timing of the 'critical peak' is applied universally across the SP-Ausnet network and, hence, does not necessarily target the timing of more localised network constraints.

Given the general lack of cost-reflective network charges, business users have no (or little) incentive to reduce their consumption during network peaks. This contrasts to the variation in wholesale energy costs which large commercial and industrial users are generally exposed to.

The retail market is highly competitive for business users willing to accept retail offers that pass-through some variability in wholesale energy costs. Some large industrial users accept nearly full pass-through of spot market prices, preferring to curtail their use or operate standby generation if prices exceed a nominated threshold. In exchange for agreeing to be exposed to greater price volatility, such businesses receive a cheaper price for their load under non-peak conditions. Some businesses will manage price risks using sophisticated energy management systems and internal expertise, or by contracting with generators; others prefer to allow an aggregator of demand management services to assist with the development of demand response solutions.

Uptake of non-price demand management

As required under the NER, it is common practice for network businesses to assess demand management solutions as a means to cost-effectively defer planned network augmentation projects (sometimes referred to as 'non-network alternatives').

Investigation of demand management options by network businesses draws on information about spatial peak demand at each zone and sub-transmission

substation, the characteristics of the load (including the timing of peaks), the configuration of the network and the customer mix. Detailed load flow analysis is then used to identify a target reduction in peak demand that could defer a network augmentation.

Demand management solutions investigated by network businesses, that the Commission is aware of, are varied (box 9.6). The most feasible solution often depends on the location of a constraint in the network. The Commission understands that where demand management has been evaluated as a possibility to defer a capacity driven augmentation, 75 per cent of the network expenditure that would have been required in the absence of demand management has been for zone substations and 11kV distribution feeders (Ausgrid, pers. comm. 2012).

Despite the efforts of network businesses to pursue demand management to delay network investment, in practice very few projects have been assessed as viable. For example, Ausgrid performed 86 demand management screening tests over a period of 3 years, but found that only 10 projects were viable (counting only the short term benefits of network deferral) (table 9.2).

Table 9.2 Very few non-network solutions are authorised
Ausgrid

		2008-09	2009-10	2010-11
Screening tests	No.	42	26	18
Investigations	No.	9	6	3
Projects authorised	No.	5	3	2
Project cost	\$ million	3.95	2.75	1.37
Project savings (value of deferral)	\$ million	13.4	6.46	4.17
Proportion of Augmentation capital allowance	Per cent	3.6	1.3	0.7

Source: Ausgrid submission to AEMC PoC Review Issues Paper, p. 12.

Demand aggregators can step in to arrange contracts with end-users and assist with identifying and implementing cost-effective load reduction options on behalf of networks. A particular feature of such arrangements is that the aggregator takes on the entire risk of a demand management solution not meeting the agreed reduction in demand.²² Demand aggregators tend to target load reductions from large business users, as the costs of negotiating and setting up an individual arrangement with end users (including ‘site enablement’ and real time monitoring capability)

²² To manage this risk, aggregators (such as EnerNOC) usually over contract the required demand reduction with end-users and closely monitor or remotely control their load. To the extent that an end user retains ultimate control over their load, an aggregator ‘coaches’ them to ensure they perform as expected when a reduction in load is to be dispatched.

typically amounts to thousands of dollars per site. Consequently, 5-year contracts are normally established with end-users.

Box 9.6 Demand management options considered by network businesses

Demand management options considered by network businesses often involve:

- contracting with existing standby generation installations
- negotiating with commercial and industrial users to contract a quantity of peak demand reduction that can be called upon when required. For example, the electricity demand profile in Tasmania is dominated by four large industrial businesses (ESIEP 2012), with whom agreements can be reached (usually at low cost compared to smaller users) to curtail their use of system capacity upon request²³
- deploying temporary (modular diesel-fuelled) generators at suitable sites in the network requiring reduced demand on 11 kV feeders and zone substations. Network businesses usually lease such generators under tender arrangement, with each 5 MVA module costing around \$1.25 million per season plus hourly operational and maintenance costs of \$2000
- residential load control of air-conditioning and pool pumps. These solutions have only been evaluated as trial projects to assess their technical feasibility and, for air-conditioner load control, performance at maintaining customer comfort levels. Large scale implementation has not yet been costed, but early results suggest that a 30 to 50 per cent reduction in the normal peak operating load of air-conditioners may be achievable — equivalent to 20-30 per cent of total peak consumption (Futura 2011)
- commercial building energy efficiency programs. Cost-effective options usually target lighting upgrades. A previous project by Energy Australia offered businesses around \$200/kVA for demand reductions, but when all expenses were included the cost of the project was \$115 000, hence costing \$450/kVA.

Source: Energy Australia and Transgrid 2009.

A one off survey in 2010 of Electricity Network Demand Management in Australia found that, in 2010-11, demand management by network businesses was expected to displace 0.8 per cent of the total peak demand (equivalent to 367MW, and more than 4 times higher than in 2007-08) (Dunstan et al. 2011a).

Futura Consulting recently sought to quantify the volume of peak demand management in the NEM (2011). They found approximately 430 MW of peak demand reduction

²³ Industrial customers account for around 60 per cent of Tasmania's total electricity consumption, with four major industrial customers using around half of the energy supplied by the Tasmanian power system. Under the System Protection Scheme, load shedding by industrial customers occurs instantly in the event of an unplanned outage of Basslink while energy is flowing into Tasmania.

was sourced from commercial and industrial customers,²⁴ which is equivalent to around 1 per cent of system peak demand in the NEM. This is suggested to be low compared to international benchmarks. For example, the equivalent peak load reduction is 6 per cent in the Californian market (Faruqui 2011).

An annual survey undertaken by AEMO of demand management by retailers, network businesses and demand response aggregators indicates that demand response amounts to less than one per cent of the NEM-wide peak (table 9.3; AEMO 2012a).

Table 9.3 Levels of demand response from all reported sources
Aggregate energy consumption (MW) by likelihood of businesses participating in demand management for the 2012-13 summer

	<i>Very likely</i>	<i>Even chance</i>	<i>Very unlikely</i>
Queensland	78	111	111
New South Wales	31	71	98
Victoria and SA	109	121	149

Source: AEMO 2011b, ESOO, p. 3.50

While the survey is intended to capture the demand management activity of retailers, evidence of substantial load shedding following wholesale market price spikes suggests the survey underestimates actual demand management activity of their customers. For example, investigations by the AER reveal that following price spikes in the spot market in NSW:

- during a period of high temperatures, around 500 MW was shed in November 2009, following a price spike to \$6200/MWh (Futura 2011, p. 43)
- an episode of disorderly bidding (chapter 18) by generators on 4 February 2010 resulted in prices varying from \$10 000/MWh to the market floor price (-\$1000/MWh) and 538 MW of load being shed over the space of just one hour (AER 2010d).

Such examples demonstrate the willingness of some industrial businesses to respond to commercial incentives for load management. Depending on the size of the payment such end-users would require to curtail their load (or price they would be willing to avoid), such evidence may point to a greater source of demand response capacity for networks to tap into.

²⁴ Including curtailable load arrangements, dynamic peak pricing and the use of standby generation.

9.6 Why is the uptake of demand management so low?

Despite the conceptual appeal and stated potential for wider implementation of demand management, there has been a low level of uptake across the NEM (particularly by network businesses). This is likely to reflect several factors, including:

- the absence of smart meters for the majority of residential households. There is likely to be underinvestment in smart meters to the extent the benefits are ‘split’ along the supply chain (chapter 10)
- where smart meters are available for residential customers, their use for demand management may be restricted. For example, the cost of smart meters has been incurred in Victoria, but the Government has directed a moratorium on their effective use for time-based pricing until mid-2013 (chapters 10 and 11)
- the National Electricity Rules (and their application by the AER) may limit the incentives of distribution businesses to implement demand management solutions, even where they offer the most efficient solution (AEMC 2012e) (chapters 5 and 12)
- risk aversion among distribution businesses in regard to implementing demand management, given their unfamiliarity with the techniques and the added complexity to their business model. For example, Ausgrid suggests that a decision to engage demand management:

... leaves the network operator with at best a marginal benefit until the next regulatory reset in exchange for a higher risk profile and more complex business model. ... In this environment there is little incentive for such businesses to be innovative, or assiduous in finding and securing [Demand Side Participation]. (Ausgrid 2011c, p. 11-12)

- the perception that customers won’t respond to prices or other market based incentives to shift loads. (This assumption is not supported by trial evidence that shows consumers can and do shift or curtail their peak consumption in response to price incentives) (box 9.3). The current lack of price signals limits consumers’ understanding about the costs of their consumption and the potential to benefit from economising, where feasible, at peak times
- retailers lack financial incentives to implement demand management. Indeed they currently have (particularly the ‘gentailers’) a financial disincentive to do so. Moreover, market imperfections, created by retail price regulation in most of the NEM, stymie more innovative business pricing models (chapter 12)
- a lack of coherent evidence to inform what constitutes a socially efficient level of demand management. Specifically, evidence from pricing trials (including elasticities) has not been made publicly available, despite the clear benefits from a broader base of knowledge to construct more cost-reflective tariffs.

-
- the impact of deterministic reliability regulations for networks may dampen any appetite for demand management (chapter 15)
 - some technologies to implement demand management, including battery storage and distributed generation, are not yet commercially viable (chapter 13).

These issues are evaluated more specifically in later chapters and, while some have important implications for the way a demand management approach such as cost-reflective pricing might be implemented, in the Commission's assessment they should not necessarily preclude the use of such an approach.

Before embarking on an assessment of specific solutions to address the potential barriers to the wider uptake of demand management, it is important to know that the potential net benefits are material. To this end, the following section evaluates, more systematically, past reviews and recent evidence from trials and experiments on the costs and benefits of demand management.

9.7 Gauging the prospective benefits and costs of demand management

As noted in section 9.1, growth in peak demand is likely to necessitate or bring forward potentially billions of dollars of otherwise unnecessary network investment, for which consumers ultimately pay. Reflecting this, estimates suggest that \$11 billion of capital investment in system capacity is used for only 100 hours per year.

Demand management thus offers the potential for significant benefits, including:

- in the short to medium run, investment savings from delaying or removing the need to augment network capacity
- in the long run, a more efficient electricity distribution system — where expansion of peak capacity only occurs if consumers are willing to pay for it.

However, implementing demand management solutions (especially at a household level) brings its own costs and difficulties. The main costs of demand management are:

- the costs of implementing any scheme — including the costs of smart meters, customer education and business transition costs, such as costs to retailers and network businesses associated with IT and other technology investments
- any perceived loss in consumers' wellbeing from exposure to cost reflective prices.

Demand management initiatives should be pursued only if it can be concluded with reasonable confidence that their implementation will yield benefits in excess of their

costs. Such assessments ultimately need to be made on an initiative-by-initiative basis, taking into account localised considerations and different implementation strategies that may affect the present value of the stream of benefits and costs entailed. Complementarities that may occur between different initiatives would also need to be considered. For example, smart meters and time-based pricing can be adopted in tandem with the option of direct load control of air-conditioners, which can support consumers' acceptance of new pricing approaches and achieve a more reliable demand response.

A number of studies have examined the benefits and costs of demand management (ESC 2002, 2004; CRA 2006; NERA 2008a, 2008b; EMCa 2008; CRA 2008a, 2008b; KPMG 2008; Deloitte 2011). By revisiting these studies and drawing on new information, particularly from the rollout of smart meters in Victoria, the Commission has sought to gauge the prospective gains from the further adoption of demand management in Australia. As an input into the assessments of specific initiatives in later chapters, it also aims to:

- identify information that could be pivotal in approving specific demand management projects
- highlight gaps in current knowledge of relevant costs and benefits
- draw out implications for the implementation path of the draft recommendations.

To those ends, the Commission has compiled indicative estimates for a number of demand management initiatives (which are available on request). The analysis incorporates estimates of untargeted 'time-of-use' pricing, direct load controls, critical peak pricing and critical peak rebates. Sensitivity analysis is included to reflect uncertainties around key components of the estimates.

The following subsections summarise the key findings from the analysis.

Some demand management options offer substantial benefits

The Commission's calculations suggest that the further adoption of demand management, if implemented efficiently, could yield net benefits of between \$1500-3400 per household in net present value terms. The largest (and most certain) benefits are likely to accrue when demand management defers or avoids the need for network augmentations. This does not include the scope for gains from the nearer-term adoption of more efficient time-based network pricing for commercial and industrial end-users. (Critical peak network charges are not generally applied to such users, and even where they are, they are not appropriately targeted to local network conditions.)

However, as discussed further below, the actual extent of the estimated benefits depends crucially on the manner in which demand management is implemented — for example, under some implementation scenarios, some initiatives are forecast to deliver net costs (table 9.4). Accordingly, some of the scenarios presented in table 9.4 do not represent demand management approaches that, given current smart meter and technology costs, would realistically be of interest or considered sensible options. For example, the demand management approaches involving an immediate national smart meter rollout illustrate that this would not be advisable. They are provided to highlight the importance of a more targeted approach to where and when investments in such meters occur. The estimates attached to those scenarios also support the need for rigorous cost benefit analysis to accompany the planning of smart meter rollouts or other feasible technology investments — an issue taken up in chapter 10.

There are uncertainties about the exact magnitude of the costs or benefits attached to some of the key components of the estimates. Over time, and with iterative experiences in implementing demand management approaches, it should be possible to identify a narrower range of estimates.

Table 9.4 Relative merits of stylised demand management approaches
Benefit-cost ratios, indicative estimates^a

<i>Scenario</i>	<i>Low</i>	<i>Mid-point</i>	<i>High</i>
National smart meter rollout with critical peak demand management	0.5	1.0	2.6
National smart meter rollout with time of use pricing	0.3	0.6	1.1
Direct load control in the absence of smart meters	0.1	0.8	6.3
Limited smart meter rollout with critical peak demand management	0.8	2.1	5.8
Limited smart meter rollout with critical peak demand management and one year deferral of distribution network infrastructure	1.0	2.8	7.6

^a A benefit–cost ratio less than one implies that the stream of discounted costs was more than the stream of discounted benefits. The low case for most scenarios is below one, indicating a risk of a net cost. If a scenario has higher benefit–cost ratios in all cases, it is more likely that the scenario would be of net benefit. However, a more risky project may be warranted if benefits can be obtained across a larger proportion of peak consumption — such a scenario is more likely to warrant additional efforts to mitigate the potential for downside risks

Source: Commission estimates.

Avoiding or deferring network augmentation yields significant benefits

Reducing the growth in peak demand can ameliorate the need for additional investment. There are significant costs involved in providing capacity to supply peak demand; as such, any (reliable) reduction in peak demand growth may give

rise to significant investment savings. The Commission reviewed existing estimates of the long-run marginal cost of delivering an additional kW to an end user during peak periods (Futura 2009; Oakley Greenwood 2010b; ESAA sub. 23), and found the following ranges plausible:

- \$90-180 for expanding distribution capacity
- \$90-110 for additional peak generation (open cycle gas turbine) capacity
- \$36-90 for expanding transmission capacity.

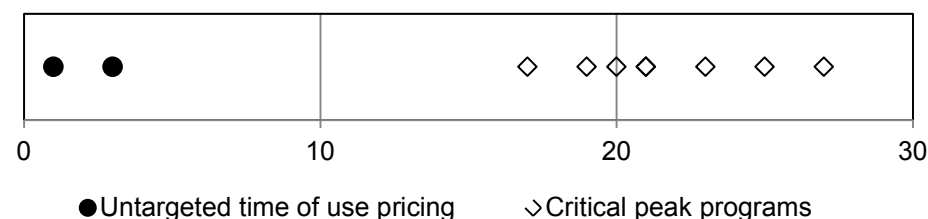
While growth in peak electricity consumption is a critical driver of network augmentation, parts of the network will have differing levels of spare capacity. The potential for benefits from introducing demand management are likely to be highest in parts of the distribution and transmission network where electricity consumption during critical peak periods is reaching capacity. However, such benefits can only be realised if demand management can sufficiently temper the growth in critical peak consumption to defer or negate the need to augment the network.

Not all forms of demand management are effective at reducing peaks

In Australia, a number of demand management schemes have been trialled or introduced. They have included untargeted TOU pricing (unrelated to peak events), critical peak pricing (or rebates for curtailing electricity consumption during critical peak events) and the use of direct load control technology (also targeting critical peak events).

The reduction in energy use during critical peak events has been substantially lower under untargeted TOU schemes than under other demand management schemes (figure 9.8). Untargeted TOU charging is less effective than other demand management approaches because it conveys peak price signals that apply routinely throughout the year, rather than providing targeted incentives for consumers to reduce consumption during a far fewer number of critical peak events.

Figure 9.8 Reduction in peak electricity use for Australian trials
Per cent reduction in peak electricity use, by type of demand management



Data source: Futura 2011

The likely scale of reduced peak energy use from a wider roll-out of demand management in Australia may be smaller than that achieved through trials. For example, some trials have restricted eligibility to consumers that have greater scope to reduce peak energy use (for example, households with air conditioners) (Futura 2011). In addition, trials intensively educated participants, provided technologies to assist participants monitor their power use, and some even funded or subsidised the purchase of more energy efficient appliances. Combined with the fact that most pricing trials were not undertaken over an extended period, and those that were showed some erosion in demand response over time, it is likely that lower reductions in peak energy use may be achieved outside of trial settings.

Smart meters are a crucial cost item

Implementing demand management requires new infrastructure of its own (chapter 10). Smart meter infrastructure is already in place for large commercial and industrial users, and therefore there is no physical barrier to the utilisation of greater demand management techniques for these users. By contrast, the transition costs for the residential and small business customers in the NEM currently using traditional ‘accumulation’ meters can be significant.²⁵

In Victoria, the rollout cost more than \$700 per meter, with further ongoing operating costs of \$20-30 per year. This is greater than the ‘building block’ forecasts produced by Energy Marketing Consulting associates (EMCa 2008), which suggested transition costs of well under \$500 per meter. While the EMCa report appears to have underestimated the complexities of a rollout, in particular in project management and IT, the market for smart meters is maturing and prices are declining. The cost of rolling out smart meters in future should be lower than the Victorian experience, but it is unclear how much lower. This is a major source of uncertainty. If smart meters were rolled out across the NEM, the cost difference between the Victorian and any future experiences could be over a billion dollars (figure 9.9).

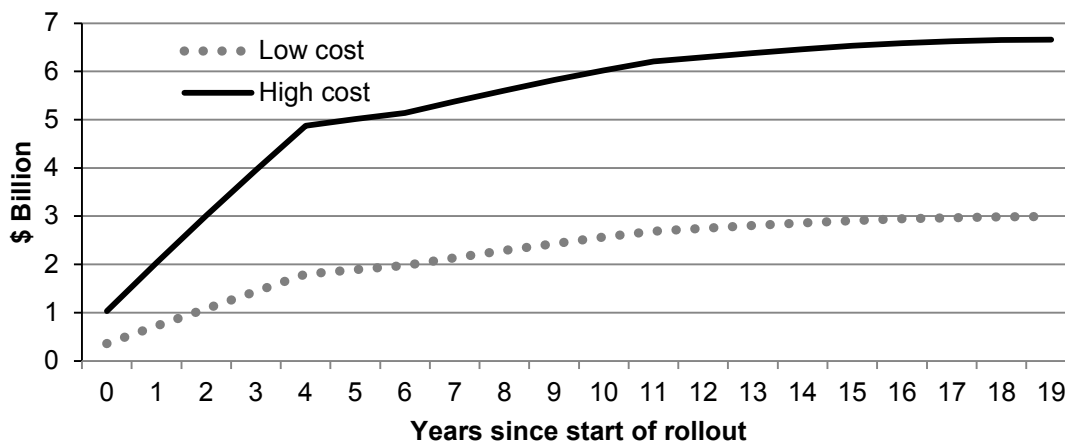
If the Victorian experience were replicated across the rest of the NEM, a transition to advanced metering would result in an increase in the average metering charges of \$80-100 per year (Deloitte 2011, Pers. Comm.).²⁶ If technological and policy improvements lowered the cost to \$500 per meter (as forecast by EMCa 2008), the average increment for smart metering charges falls to \$50-60 per year.

²⁵ While consumption could be metered in half-hour increments by a simple ‘interval meter’, an approach taken by Ausgrid, this would not provide timely feedback to customers about their power use, or any of the other benefits provided by smart meters.

²⁶ This includes a reduction to cover the cost of replacing accumulation meters that would otherwise have come to the end of their work life.

Figure 9.9 **Indicative cost of smart meter roll out across the NEM**

Cumulative gross costs (discounted) based on highest and lowest cost estimates^a



^a The highest cost estimates are based on the Victorian roll out which includes the purchase and installation of smart meters, communication and billing systems and providing consumer access to their consumption data. It is unclear if it would include costs of communicating critical peak events to consumers.

Data source: Indicative Commission estimates

Smart meters would provide other benefits

A number of potential benefits from a smart meter roll out have been identified that are largely unrelated to demand management but can help to offset the cost. While the list of possible benefits is long, the clearest of these are:

- accumulation meters and manual meter reading should not be required
- connections, disconnections and special meter reading (such as when consumers dispute their bills) can be conducted remotely
- networks can be notified about outages almost immediately, allowing them to respond more rapidly.

Recent Australian studies provide varying estimates of such benefits from smart meters (NERA 2008b; Oakley Greenwood 2010b; Futura 2009; Deloitte 2011). Using information from the most recent analysis of Victoria, the average benefit from each meter would be in the range of \$60-65 each year (Deloitte 2011). This is a little higher than the comparable Australia-wide figure of \$55 from CRA (2008a).

These other benefits associated with the introduction of smart meters would increase the likelihood that demand management would pass a net benefit test.

The time path of demand management affects the outcome

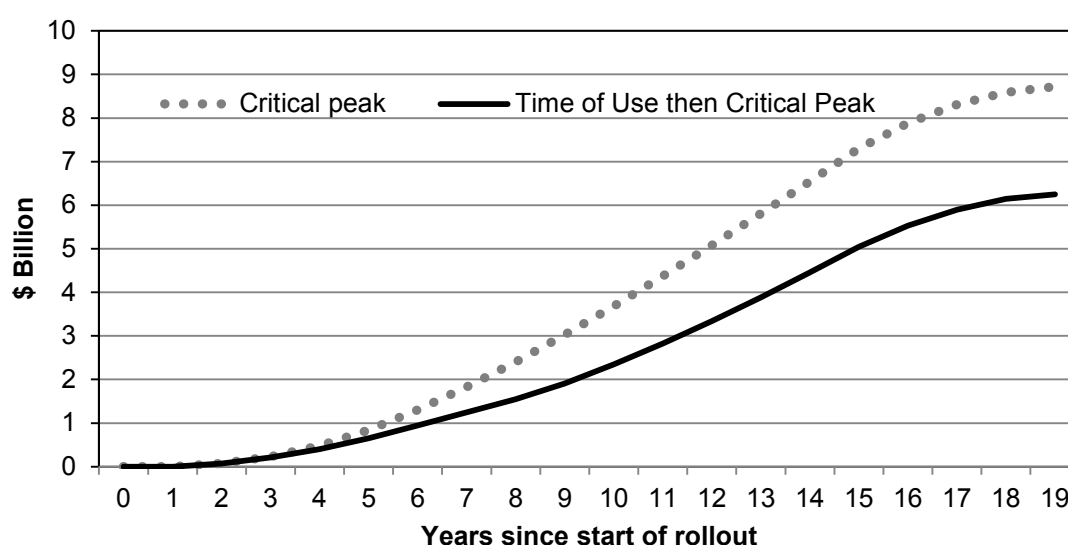
At present, most households face an electricity network pricing structure that does not vary by time of day or season. As such, consumer acceptance of demand management approaches is likely to be greater if there is a gradual transition to more targeted schemes, such as:

- starting with a tariff scheme that is not time-based
- moving to prices that vary by time of day but which do not vary according to peak demand events (untargeted time of use tariffs)
- finally, moving to full cost reflective pricing that includes pricing for peak demand times.

The reduction in energy consumption at critical peak periods is likely to be very low under retail pricing schemes such as flat tariffs (with higher than current prices) or untargeted TOU charging. A particularly slow transition to more targeted demand management tools is likely to forego an otherwise larger reduction in energy consumption during critical peak periods. Over the lifespan of the smart meter, this leads to a lower value of benefits for consumers (figure 9.10). Indeed, the Commission's analysis suggests that if the transition to more robust forms of time-based pricing is too slow, the case for rolling out smart meters in the medium term becomes commensurately less advisable.

Figure 9.10 Indicative benefits of demand management savings

Cumulative value of deferral of network augmentation assuming critical peak arrangements are introduced immediately, or if untargeted TOU is used for the first five years



Data source: Indicative Commission estimates

Summing up

The Commission's analysis suggests that demand management has the potential of delivering significant benefits, but that the magnitude of the net benefits attainable in practice depends on the particular initiatives adopted and the way in which implementation occurs.

Inevitably, there remains uncertainty about the precise magnitude of some of the costs and benefits, for example in relation to smart meters (and all the associated costs of their full implementation), which are critical for effective demand management. Most of the available evidence suggests that the costs in the Victorian rollout were higher than anticipated, and their effective use has not yet really begun. Nevertheless, the capital costs of smart meters will fall over time, making demand management schemes progressively more viable. The benefits from deferring network expansion will be pivotal in determining the viability of rolling out many demand management schemes.

Ultimately, realising the potential benefits of demand management relies on a sufficient number of electricity users choosing to respond to price signals and adapt their consumption habits. Accordingly, it is essential that consumers are appropriately supported in adjusting to new pricing approaches, especially to avoid a prolonged transition that would forego the potential for much larger efficiency benefits over the longer term.

10 Technologies to achieve demand management

Key points

- Efficient implementation of demand management technologies will be fundamental to steer electricity consumption towards a lower cost future. However, because the benefits from demand management are split across a number of parties, free rider problems can hinder uptake of technologies to support demand management.
- The costs and benefits of such technologies are uncertain and change over time. However, smart metering infrastructure (including the smart meter itself, IT equipment, back-end software, and two-way communication equipment) underpins most forms of demand management (including time-based pricing and most load management solutions).
 - With this core technology in place, it is not necessary to prescribe the uptake of other technologies, including the ever-broadening range of ‘add-on’ technologies (to inform customers about electricity usage, prices and to automate demand response).
 - Nevertheless, given uncertainty over the net benefits from smart meters, it is prudent to assess the potential of alternative technologies to achieve demand management (that do not necessarily require a smart meter), including direct load control technologies and demand limiting switches.
- Governments around the world have generally responded to incentive problems stalling investment in smart meters by mandating roll-outs or using similar regulatory tools. Most businesses have smart meters, but outside Victoria only a small share of residential consumers currently have such meters. Even still, the Victorian roll-out has caused concerns due to a moratorium on their effective use and higher than anticipated costs.
- A rapid roll-out of smart meters may not be immediately practical or efficient. Within any constrained network region, a sufficient penetration of smart meters is needed to realise network savings. Universal adoption within a network area would support these savings, while also reaping economies of purchasing and minimising other costs.
- A planned roll-out is most likely to deliver net-benefits, whereas a market-based approach would involve significant risks. Distributors should be responsible for staged roll-outs on a region-by-region basis, subject to a cost-benefit test (and the relevant jurisdiction lifting retail price regulation — chapter 12). The AER should encourage distributors to minimise costs by benchmarking adherence to a commercial standard.
- Costs should be borne by end-users, with low-income households to receive appropriate assistance. Time-based network tariffs are an essential prerequisite to the rollout of smart meters, which should be accompanied by community consultation.

Electricity demand management relies on technology solutions to achieve time-based pricing and to support load management. Advanced metering infrastructure — so called ‘smart meters’¹ — are used to implement nearly all forms of demand management, including efficient pricing, some load control programs and distributed generation options. (Options to implement demand management in the absence of smart meters are more limited and are generally more difficult and costly to implement than if smart meters were available.) Underinvestment in smart meters and consequent failure to implement efficient demand management could lead to costly overinvestment in network infrastructure to meet peak loads.

As discussed in chapter 9, there are important question marks over the potential costs and benefits of specific demand management technologies, including how these might change over time. There is also considerable uncertainty around how consumers’ behaviour patterns might change with a greater focus on demand management, and what role technologies will play in supporting such behavioural change. Further, future changes to the patterns of electricity use, such as from the uptake of electric vehicles, could potentially exacerbate peak demand or, if carefully managed, might provide an opportunity to smooth out consumption patterns. To that end, efficient implementation of demand management technologies and price signals will be fundamental to steer electricity consumption towards a lower cost future.

To ensure the potential for benefits from demand management are realised, and that investments in enabling technologies are of value to consumers, it is important that consumers be consulted about the imperatives for change. Failure to do this adequately could lead to a consumer reaction that undermines the case for investment in technologies and stalls the gradual progression towards pricing changes that will benefit consumers over the longer term. The Victorian experience of poor engagement with consumers confirms the risks from not persuading consumers in a carefully coordinated manner and at an early stage.

This chapter primarily looks at whether smart meter technology should be more widely implemented in Australia. However, because available technologies and their costs and benefits are uncertain and likely to change over time, the net present value of all feasible options should be evaluated. In addition, given the unexpectedly high cost experience of the Victorian roll-out (box 10.1) it is prudent

¹ The term ‘smart meters’ is used to describe the smart meter itself, and associated technologies, such as IT equipment, back end software, and two-way communication equipment.

to consider alternative technologies. Other possibilities to achieve demand management options that do not rely on a smart meter might include²:

- direct load control³ — where, with the prior agreement of the customer, the power supply to household appliances can be remotely controlled (by retailers or distributors) to reduce the draw on network capacity at peak times. For an air-conditioner, this involves cycling the compressor on and off at regular intervals (but with the fan still running)
- demand limiting switches to keep demand within an agreed threshold at peak times.

Section 10.1 provides some background to demand management technologies and recent experiences with their implementation. Section 10.2 looks at the challenges to implementing smart meters, including why coordinated action is appropriate and why a regulated approach is considered more feasible than a market-based solution. The section then discusses why a distributor is best placed to undertake the roll-out and ways that a distributor-led roll-out could be implemented. That includes whether approval of funds should occur within the existing incentive regulation framework or as a separate item of expenditure given the peculiarities of the investment (including that, at this stage, distribution businesses may not have fully aligned incentives to roll-out smart meters and apply more cost-reflective network charges). Issues surrounding how other technologies to reduce peak load inefficiencies could be implemented (including without relying on smart meters) are examined in section 10.3.

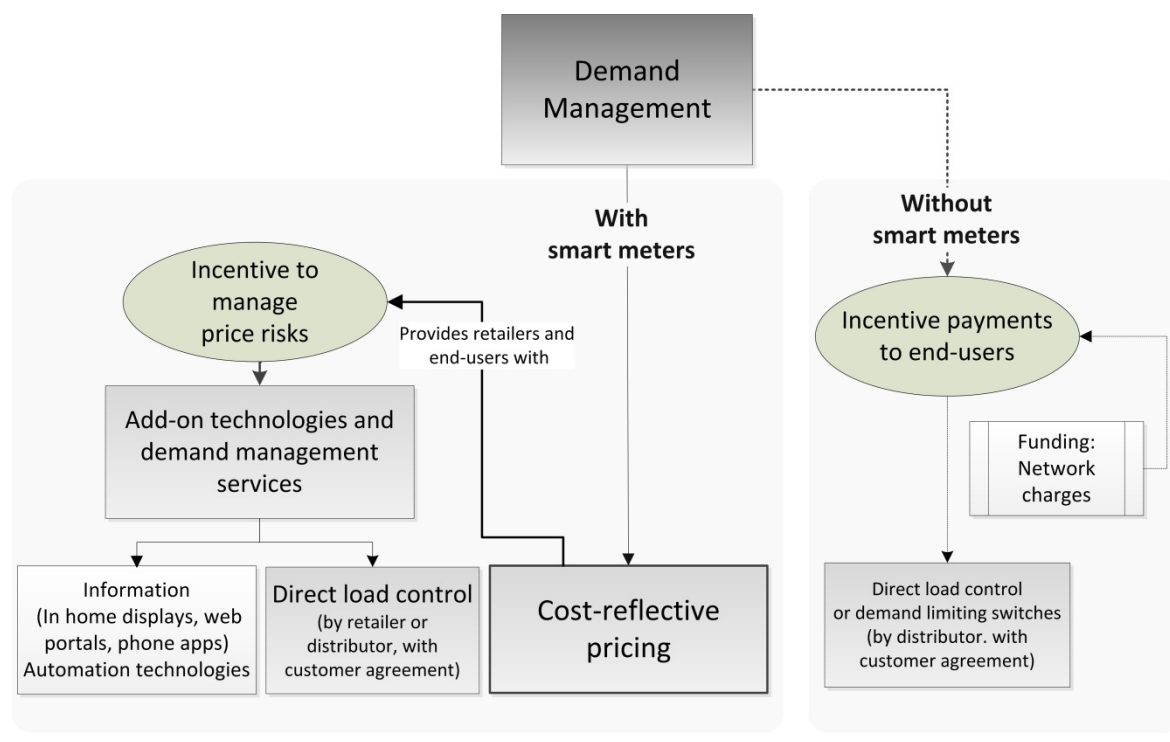
10.1 About demand management technologies

Demand management technologies are about using the supply-side infrastructure more efficiently and intelligently — via smart meter infrastructure, or (in the absence of smart meters) through direct load control (figure 10.1). Under either approach, the goal is to achieve a ‘demand response’ — reduction in peak demand — which allows less expenditure on peak capacity across the network and helps to ease upward pressure on electricity bills.

² Electricity storage and distributed generation technologies could also be alternatives, but these are addressed in chapter 13.

³ Direct load control (DLC) can be implemented both with and without a smart meter. If a smart meter is available, DLC can be implemented with greater flexibility and for a lower incremental cost.

Figure 10.1 Technology pathways to achieve demand management



Understanding smart meters

Smart meters measure and record (at 30 minute intervals) how much electricity a household or business is using. Such meter readings are communicated directly to a central data collection point, removing the need for physical meter reading. It is possible to invest in additional technology and software so that households and businesses can access detailed information from the smart meter about their electricity use. Current options include through in-home displays, web portals or via a home ‘gateway’ — a connection between the smart meter and a home computer and the internet (figure 10.1).

Smart meters facilitate a move to an environment where consumers can observe the direct impact of time-based pricing (prices that reflect the full cost of supplying electricity at particular times). As such, the phasing in of time-based prices usually accompanies smart meter roll-outs.

The majority of Australian households outside Victoria do not have smart meters and, as such, do not face time-based pricing.⁴ Further, a significant proportion of those households who do have smart meters (mainly in Victoria) also do not

⁴ Although many households face a separate off-peak tariff for their directly wired electric hot water service.

currently face time-based pricing. Victoria is in the paradoxical position that it has widespread availability of smart meters, but a moratorium on time-based tariffs for residential users until the middle of 2013, at which point it will be voluntary for customers to switch to a simple time-based tariff (O'Brien 2012). (Meanwhile, customers are paying for the cost of the roll-out, adding around \$25 a quarter to household's electricity bills.) In contrast, a much higher share of business users have smart meters and, to varying degrees, already face time-dependent prices (albeit that this mostly reflects variation in wholesale power prices rather than time-based network charges).

In a number of countries (such as in France, much of the US, Canada and China), household and business customers face time varying tariffs (albeit that the price signals they face are often only partly cost-reflective) (CRA 2005).

Smart meters can promote better demand management and operational efficiencies

Smart meters require a relatively large outlay, but they can provide versatile demand management options. The newer generation smart meters allow two-way flows of information, which in addition to time-based pricing, can allow:

- control of customer equipment, such as direct load control of air-conditioners and pool pumps, subject to their agreement
- interactions with consumer 'add-on' technologies, to inform a customer's energy use decisions and enable automated 'set and forget' controls.

These demand management solutions can help reduce the transaction costs for consumers in responding to price signals and, hence, can activate a higher level of demand response than might otherwise be the case. For example, they can assist end users who might feel inconvenienced by managing their electricity use in the absence of 'no-fuss' automated solutions.

Network businesses can also operate their grid more intelligently with smart meters, including by remotely connecting and disconnecting customers, remotely reading meters and gaining real time information about outages and other reliability outcomes. These benefits of smart meters are often referred to as operational efficiencies.

Box 10.1 **Lessons from the Victorian smart meter roll-out**

In 2006, the Victorian Government directed distributors to install 2.4 million smart meters in Victorian homes from 2009–2013, with consumers directly paying for the cost. The roll-out was expected to deliver large net-benefits, including cheaper energy use, improved supply efficiency and increased retail competition. However, subsequent revisions to the cost-benefit analyses that informed this decision⁵ suggest that the roll-out is now likely to involve a net cost over its lifetime.

- In 2008, the MCE (2008) estimated the prospective cost of a smart meter roll-out in Victoria as \$673-1089 million, while the Victorian DPI (DPI 2008) estimated it at \$1160-1560 million.
- In under two years, revised estimates indicated that the expected total cost of the roll-out would be roughly double that anticipated by various parties in 2008.

Different categorisation of costs makes it difficult to identify which costs were higher than predicted, but IT and installation costs in particular were more costly than expected (EMCa 2008; Deloitte 2011).

On the benefits side of the ledger, Deloitte (2011) found \$400 million fewer benefits from ‘efficiencies in network operations’ than had been previously estimated in reports by Futura (2009) and Oakley Greenwood (2010a). Consumer benefits from time-based pricing have been delayed by the Moratorium.

In 2009, the Victorian Auditor-General’s Office audited the performance of the smart meter roll-out. It found various problems with the project, including:

- a lack of detailed economic analysis and flaws in the supporting cost-benefit study, and insufficient evaluation of the consumer impacts, project (and technology) risks
- a need for stronger project governance by the responsible state department, especially given the scale and cost of the market intervention
- inadequate community engagement, given the significant effect on consumers.

Overall, it appears that the Victorian decision to roll-out smart meters was premature and/or poorly planned with inadequate knowledge about smart meter technologies, their costs and associated risks. Further, there was inadequate consumer education about the potential changes and benefits post the roll-out. More consumer testing may have helped to avoid this outcome. In addition, the pace and mandatory nature of the roll-out may have inflated costs. The meter specification and performance requirements may also have been overly restrictive and, if interpreted strictly by network businesses, inconsistent with accepted commercial standards. Moreover, the failure to enact pricing reform since the roll-out has compromised a major source of potential benefits to consumers. Not surprisingly, consumer dissatisfaction with the process has been high, which may further frustrate subsequent attempts to implement pricing changes.

Sources: Victorian Auditor-General 2009; Deloitte 2011; Futura 2009; Oakley Greenwood 2010a.

5 Two cost-benefit studies informed the Victorian Government’s decision — a 2004 study of installing manually read interval meters and a 2005 analysis of adding two-way communication technology.

Mixed results from roll-outs and uncertainties about costs and benefits

Smart meters are a relatively new, but not revolutionary, technology. The associated hardware, IT and communications technologies are continuing to mature, which is consistent with declining costs (or stable costs with increasing functionality) over time. For example, the price of smart meters in the European market is forecast to decrease by over 30 per cent between 2010 and 2017 (Frost and Sullivan 2011). This is driven mainly by mass-market cost reductions, with 2 providers serving 90 per cent of the European market.

Evidence about the impact of smart meters is increasing with the completion of a number of large-scale roll-outs.⁶ Smart meter roll-outs have occurred or are occurring in many European countries, including France, Italy, Spain, Sweden, The Netherlands and, more recently, in the UK.⁷ Smart meters are also common in many areas of the US and Canada. The most prominent Australian example of a broad scale roll-out is in Victoria.

Both international and Australian experience demonstrates that a carefully managed implementation is crucial to realise the potential net-benefits from smart meters. For example, the roll-out in Victoria faced multiple setbacks, including implementation costs that far exceeded original estimates. The benefits from the Victorian roll-out are also likely to be lower than planned, given the initial moratorium on time-based tariffs. That and inadequate community engagement led to a significant number of customers refusing to have a meter installed.

The costs of smart meters are routinely evaluated prior to any roll-out, but there are a number of uncertainties which makes it difficult to estimate costs. In Victoria, the total costs over the lifetime of the meter are likely to be around \$800 per meter. While accurate comparisons are difficult, it appears some international roll-outs have occurred more cheaply than the costs experienced in Victoria (although the functionality of meters is usually more limited and the associated communication systems slower and less versatile). Nevertheless, if evaluating international projects on a cost per meter basis, estimates vary widely, ranging between \$114 and \$740 in 2007 values (Rousseau 2007).

⁶ The term roll-out refers to a coordinated program to install smart meters in a given geographic area. Although this may imply some degree of universality, it does not necessarily imply a government-mandated roll-out throughout a complete jurisdiction.

⁷ The UK is commencing a roll-out of 53 million smart meters to all residential properties and small and medium businesses over the period 2014-2020. The project is expected to deliver a net-benefit of £7.2bn (DECC UK Smart Metering Implementation Programme 2012).

The Commission's attempt to quantify the costs (and benefits) of smart meters revealed a wide range of potential estimates (chapter 9). Roll-out and implementation costs are sensitive to small changes in a range of assumptions, including:

- the density of a roll-out and the topography, which affects:
 - the feasibility of different communications technologies (given the technical performance and associated cost of options)
 - installation costs, with an uncoordinated roll-out significantly raising the per unit cost of installing a new meter compared to a street-by-street approach
- the pace of technology changes, particularly those affecting communications options and, so-called, back-end IT software, and the resulting impact on costs
- the speed of a roll-out, including whether any market power is conferred on installers or other suppliers
- the functionality of meters, and expectations about the extent to which meter costs might decline over time and with large purchases.

The benefits of smart meters are also uncertain. They depend crucially on the application of efficient network tariffs and, in turn, consumers' acceptance of these changes and related assumptions about their responsiveness to prices. As discussed in chapter 9, the benefits will also vary according to the length of the transition to efficient network pricing structures, and the extent that retailers pass these through to end-users.

Alternative options are more limited

Noting the apparent high costs and uncertain net-benefits of smart meters, any evaluation of the stream of benefits and costs from smart meters should consider possible alternatives. It is possible that lower cost technologies to implement demand management could yield higher net benefits.

It is important to evaluate the future stream of costs and benefits of alternatives

Alternatives to smart meters are less 'future proof', providing limited opportunity to make use of new technologies to enhance demand management and adapt to changing consumer needs. While a sunk investment in lower cost technologies would not preclude the later uptake of smart meters, because some early benefits from reduced peak consumption would already be achieved, the *incremental* net-benefit of smart meters would be more limited.

Therefore, a static analysis of alternatives is not appropriate, since it could support an initially lower cost option that locked in a lower stream of net benefits in the longer

term. To avoid this, it is important to value the net *present value* of smart meters and any feasible alternative technologies to achieve demand management.

Direct load control could be a candidate

In the absence of smart meters, direct load control technologies probably offer the most practical option to implement peak demand management.⁸ The use of direct load control technology as an alternative to smart meters is most relevant for households, as most businesses already have smart meters (reflecting the lower relative cost of a smart meter installation for larger users).

Direct load control can operate either in the presence or in the absence of price signals, and therefore, with or without smart meters. In either case, it can allow a network provider to secure a predictable peak demand response from consumers. As shown in figure 10.2, its use for a relatively short period of time can significantly ‘clip’ the peak of households’ demand compared to when it is not used.

However, in the absence of cost-reflective pricing, such schemes require the use of incentive payments to encourage participation (figure 10.1) to ensure households can realise the cost savings from reducing their peak consumption.⁹

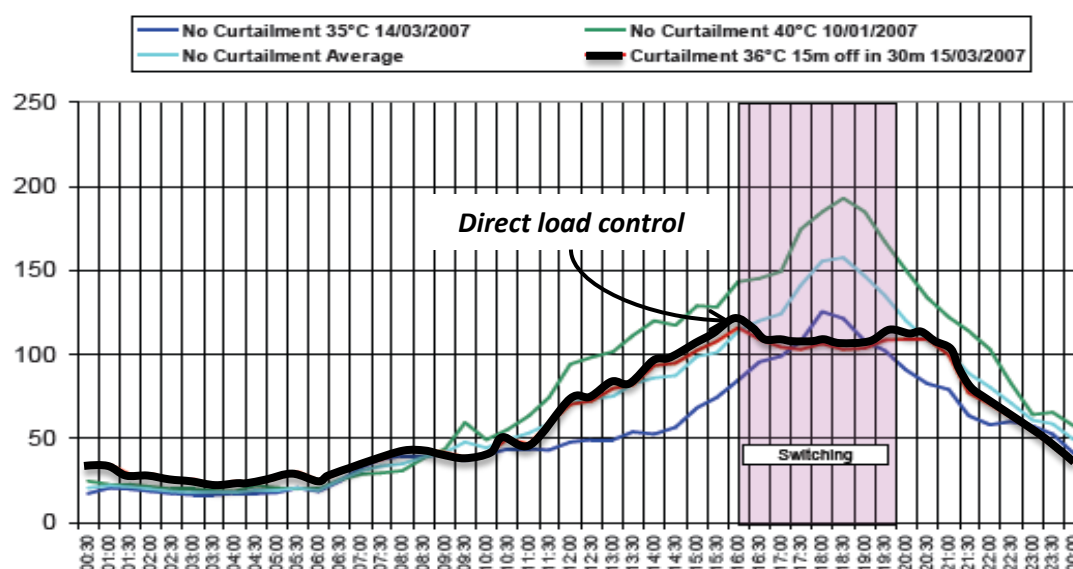
Most direct load trials have focussed on managing the peak power use of air-conditioners and pool pumps. Direct load control of pool pumps can operate all year round, similar to the off-peak programming of electric hot water services. For air-conditioners, the direct load control would typically only be used on the handful of hottest days each summer. Because cooling is highly valued during critical peaks on extremely hot days, the fan in the unit continues to operate, but its compressor is controlled to avoid the potential for network congestion over a period of up to 4 hours. Usually, the compressor of the air-conditioner is remotely cycled on and

⁸ Demand limiting switches are a similar technology approach, but are not remotely controlled by a utility provider and therefore require the end-user to pre-program decisions about which appliances to switch off during peak periods to stay within a nominated consumption limit. Such an approach tends to require greater customer effort than direct load control of household air-conditioners and pool pumps. An advantage of direct load control for network providers is that they can coordinate the use of power between households (having some households air-conditioner cycled on while others are cycles off) and can secure a more reliable demand response.

⁹ This requires individually contracting with end-users, but to avoid excessive administration costs, ‘participant’ households are typically offered a uniform flat incentive payment. Since end-users value the use of power (or particular appliances) at peak times differently, compared to a price mechanism, incentive payments are a blunt and inefficient instrument to reduce peak use. Moreover, financing such payments through a higher average consumption price can distort pricing efficiency or lead to distributional concerns (chapter 11).

off (using either, or a combination of, radio or internet communication) such that the unit does not operate for 7.5 to 15 minutes out of every half hour window.

Figure 10.2 ‘Clipping the peak’ — the impact of direct load control
KW consumed by hour on four days^a



^a Based on data from 68 homes in Glenelg South Australia.

Data source: ETSA Utilities 2008

Trials find that the managed use of the compressor and power supply to an air-conditioner has little impact on customer comfort levels if the compressor is set to operate between half and two thirds of the time (Futura 2011). Comfort levels can be increased further by extending the direct load control function to cool the house prior to and following a period of direct load control.

Technology may be a friend

Technological change will aid the management of electricity demand. While adopting new technologies can be costly, the real cost can fall dramatically over time as scale economies result from mainstream take-up. Already, technologies offer solutions to simplify managing the timing of energy consumption. The horizon of potential automated demand management solutions is large (for example, mobile phone apps can remotely control appliances). Peak load pricing and the diffusion of smart meters would accelerate such innovation.

Further, there may be grounds to accelerate the development and uptake of technologies to enable demand management. For example, some participants have suggested mandating a demand response capability in the future manufacturing

standards of key appliances, such as air conditioners, pool pumps and, in the future, electric vehicle batteries (Wilkenfeld 2011b). If consumers are informed about the benefits of having additional functionality in their appliances and it is of value to them, they will simply demand it, hence avoiding any need for intervention. However, many appliances are long lived and the benefits from choosing one appliance over another are uncertain when considered over a long period. Of course, until smart meters are more widely available to implement time-based pricing, consumers lack incentives to choose appliances with more advanced energy management features.

10.2 Some challenges implementing smart meters

Demand management and ‘split benefits’ across market participants

The benefits or costs from adopting demand management (and wider use of price signals to encourage more efficient electricity consumption patterns) often fall to more than one agent — generators, network businesses and retailers and, ultimately, consumers. However, each party may have an incentive to either resist the change if they believe they will experience a cost, or where there are likely benefits, to free ride on investments in demand management made by others — the so-called ‘split-incentive’ problem. As such, each party could decide not to invest.

A supplier that was vertically integrated along the entire supply chain could internalise the sum of possible demand management gains (and, in the case of generator, potential losses) and evaluate them against the likely costs of implementing demand management solutions. However, as noted in chapter 2, the reforms that led to structural separation of the competitive segments of the electricity sector in the 1990s — while reaping significant economic benefits — have frustrated such coordinated decision-making. Ausgrid claimed that hot water load control in NSW — introduced in the 1950s by the vertically integrated electricity supplier at the time — would not proceed now, despite the huge savings it realised (Maltabarow 2012, p. 5).¹⁰

¹⁰ Ausgrid also claimed that it could not appropriate the benefits of demand management for transmission or wholesale generation costs, and that the benefits would be eight times greater than those recognised under the current regulatory framework (Maltabarow 2012, p. 4)

Underinvestment in smart meters is a likely symptom of the split-benefits problem

It is widely recognised that, of all demand management related costs, smart meter investments suffer most acutely from the split-benefits problem:

A key economic obstacle to a market-driven roll-out is the fragmentation of benefits among multiple stakeholders, which disperses investment incentives. (Schächtele et al. 2011, p. 1)

... fragmentation across the value chain has reduced the incentive for any single player to invest in smart meter[s]. (McKinsey 2010, p. 49)

As summarised by the AEMC:

... evidence to date suggests that no single party has sufficient incentive to invest the upfront costs in installing smart meters, the benefits in terms of cost savings are likely to accrue across all parties, but should ultimately flow to the consumer. However, consumers do not have sufficient information to assess the costs and benefits, retailers do not have any certainty that they will retain a consumer long enough to recoup the costs of the meter, and distribution network service providers do not have the certainty that they would recover their investment through the price determination process. (2012t, p. 3)

The issue of smart meter investments has been widely debated, both in Australia and overseas. The split incentives problem and the significant upfront cost of smart meters have attracted governments' attention, but solutions have frequently been hindered by the potential consumer resistance to their introduction and time variant pricing. Nevertheless, a range of regulatory approaches to encourage the adoption of smart meters have been put on the table. Some governments around the world have mandated universal roll-outs or instituted regulations for staged roll-outs, such as by setting targets for the penetration of smart meters. For example, according to an EU single market directive and German Federal Government regulation, 80 per cent of households in Germany will have a smart meter by 2020. A high penetration of smart meters has also been achieved through regulation and utility-driven roll-outs in Sweden (now with 100 per cent smart meters), Italy (now with 90 per cent smart meters) and Finland (Frost and Sullivan 2011).

A key question is whether a regulated approach is necessary to encourage adoption of smart meters or whether more market-driven approaches could work better?

A lead business player?

One option to facilitate investment in smart meters would require a lead business player. The leader would coordinate the costs and benefits of demand management along the supply chain, and each party would contribute to a common funding pool in proportion to the benefits they acquire. The Australian Energy Market

Commission (AEMC 2012e) suggested a form of contractual agreement that apportioned the costs and benefits of smart meters across parties.

This approach shares similarities with Littlechild's public contest model for interconnectors (chapter 20) and seeks to address the hold-out problem among multiple beneficiaries that cannot individually appropriate the full benefit of their investments in demand management. While theoretically possible, coordinating the disparate commercial interests of potential beneficiaries from demand management raises issues of implementation costs and is likely to be a slow process.

Household action?

Arguably, consumers should individually choose whether to install smart meters and directly bear the costs since they should ultimately capture most benefits from more cost-reflective pricing and other demand management solutions that lower overall electricity costs. Having the discretion to choose whether to invest in a smart meter and face time-based pricing resonates with most consumers. It is also a position advocated by the Victorian Government and, in NSW, by the independent regulator:

The roll-out of time-of-use meters should be at the discretion of the customer or its retailer, rather than being mandated by governments or distributors (IPART 2012d, p. 8)

In IPART's view, such an approach would mean that customers with the greatest willingness or ability to shift their demand would accept time-based pricing and may potentially pay for the installation of a meter. Regardless, under any option to deploy smart meters and time-based pricing, IPART cautions that to improve productivity, a necessary criterion is that the benefits must exceed the costs.

However, there are several difficulties with uncoordinated action through individual choice:

- The incentives to purchase smart meters depend on consumers' profile of consumption and the relative prices of peak versus off-peak use. Consumers that use a significant level of power at peak times ('peaky' customers) will have the least incentive to buy smart meters that reveal their consumption profile and are likely to stay on an average 'flat' tariff.
 - However, an average tariff can only support efficient consumption (and be truly cost reflective) if the load profile of its customer base is flat or completely unresponsive to prices (box 10.2).
 - Because of this, the retention of a group of customers on an average tariff would continue to result in over consumption at peak times and inefficient investment to meet that consumption.

-
- Such consumption would continue to be subsidised by less peaky consumers and lower their incentives to purchase a smart meter (unless the ‘flat’ tariff was instead set very high, which is unlikely to be an acceptable option since, to ensure an efficient peak consumption, it would have to be set at the peak price).
 - Without smart meters, consumers do not know their own consumption profile well and the implication of that profile for cost-reflective prices.
 - Schächtele et al. (2011) summarised recent smart meter cost-benefit studies¹¹ and found that consumers expressed a high degree of uncertainty about the benefits of smart meters, reflecting highly variable consumption profiles and uncertainty about how they could adapt to time varying tariffs.
 - Wissner and Growitsch (2010; as cited in Schächtele et al. (2011)) identified informational deficiencies faced by consumers and the likelihood that if they underestimate the savings from using a smart meter (and discount for the uncertainties), they would have a low willingness to pay.
 - Currently, most consumers are generally apathetic towards their energy use. While they may express concern about the rising cost of their energy, it is a significant step to choose a time-based tariff voluntarily and bear the upfront cost of a smart meter.

Box 10.2 Flat tariffs cannot achieve efficient consumption.

The only circumstance in which a flat tariff can be efficient is if:

- the flat price is set at the cost of peak consumption, or
- consumers have a completely flat load profile, which is generally only observed in some industrial settings (which also means that peak demand would not exist), or
- demand is completely unresponsive to price signals, which is not evidenced in practice.

Other than in the circumstances above, peak consumption and resulting investments in network capacity will always be inefficient under a flat tariff, hence resulting in a sub-optimally high level of excess network capacity to meet peak consumption. The reason for this is that the efficiency savings from smart meters ultimately rely on behavioural change (a consumption response). If peaky consumers do not face a higher price for their peak consumption, other less peaky consumers would continue to subsidise their consumption choices. Even if the higher costs of peak time consumption were fully recovered through a higher than average flat price that would simply reduce the transfer of income from non-peaky to peaky consumers. While that would improve fairness, it would not avoid inefficient over investment in the network to meet the over-consumption at peak times.

¹¹ Including MacDonald (2007) for the British Government; Nabe et al. (2009) for the German Federal Network Agency; Kearney (2008); and Frontier Economics (2007).

The above considerations suggest that the voluntary uptake of smart meters by individual consumers would likely be low and slow.¹² This could significantly limit the potential for network savings and result in sub-optimal net-benefits.

A sufficient penetration of the technology would be required to:

- stem growth in peak consumption and so defer investment in peak capacity in any given region. This means that a critical mass of participants would be needed for the cost of smart meters to yield value. In addition, the more consumers with smart meters, the more valuable is access to the technology for retailers, including for them to alter their billing systems, marketing approach, hedging strategy, and offer more innovative tariffs and demand management services. Similarly, a universal roll-out would most efficiently reduce existing network costs. For example, the retention of traditional accumulation meters for a proportion of customers would raise the cost of physically reading meters (smart meters allow remote reading, connection and disconnection) and would continue cross subsidies between customers.
- reach economies of scale and minimise the costs of meter procurement, installation, communications infrastructure and supporting IT and data management systems. In particular:
 - Cost advantages accrue with installation density, making universal installation within a given area generally lower cost. (Any countervailing risks of market power that allow suppliers to inflate prices during a large-scale roll-out can be limited by sensible phasing, contracting with a variety of suppliers and avoiding excessively tight mandatory completion dates).
 - Studies find reduced roll-out costs from state-mandated comprehensive roll-outs and that these better achieve targets for uptake of time dependent pricing (Schächtele et al. 2011).
 - Within any region, the cost of smart meters is likely to be most efficiently incurred and coordinated by a single party, subject to competitive tenders.¹³

Accordingly, the value of a smart meter to any given consumer depends on the actions of other consumers, suggesting the need for their mandated adoption. In theory, there could be exemptions for low-usage or low-income customer groups. However, in the former case, it is not clear that low total consumption equates with

¹² In Germany and, in the UK, the penetration of smart meters initially relied on customers bearing a substantial portion of the upfront investment. As a result, penetration in both countries is low and has since resulted in stronger regulation to increase uptake.

¹³ While open communication standards could overcome this to some extent and promote the competitive supply of smart meters, it would not overcome the split incentives problem.

low use at critical peak times. The best evidence available (figure 10.3) is sourced from interval meter data, but unfortunately adopts an extremely broad interpretation of peak use (defined as a 15 hour period during each weekday). This limits the use of the results to isolate the contribution of average low-usage customers to the short periods where peak (and network) costs are highest.

Targeted relief for the costs of installation for disadvantaged consumers is likely to be more efficient than failing to install meters (as discussed later). This reflects:

- the relatively high cost of installing and procuring smart meters on a case-by-case basis when, for example, an exempted household moves residence or the customer opts to transfer to time-based charges
- the likely increase in fixed costs for the low proportion of households continuing to require physical meter readings. The annual cost of quarterly meters reads could be in the order of \$80-\$200 per meter, which would significantly contribute towards the cost of a new smart meter.

Figure 10.3 Relation between peak and off-peak consumption^a

Percentage of households, by kWh consumption in peak and off peak periods

Peak	<i>High</i>	3	18	44
	<i>Medium</i>	7	10	1
	<i>Low</i>	16	1	0.1
		<i>Low</i>	<i>Medium</i>	<i>High</i>
		Off-peak		

^a Based on Interval data from 1000 households. High usage is defined as 10+ kWh per day, Medium as 5-9 kWh per day and Low as 0-4 kWh per day. The peak period is defined very broadly as between 7am to 10pm on weekdays. To illustrate how to read the diagram, three per cent of households have high peak use and low off-peak use.

Data source: Simshauser 2012, p. 11 Presentation at Power of Choice Forum, 19 April Sydney.

However, many consumers are likely to resist a mandated roll-out of a technology for which they would be obliged to pay that had uncertain benefits. Mandated roll-outs leave no real decision-making power to consumers and have been found to perform relatively worse at encouraging consumers to adapt their behaviour to price signals (Schächtele et al. 2011). This emphasises the importance of retailer involvement and broad education and marketing, including:

- informing consumers about the real costs imposed by just a few hours of peak demand. People are sometimes voluntarily willing to change their behaviour if they are aware of the broader public (and private) benefits of curtailing peak demands

-
- raising awareness and showing examples of how to make savings by shifting peak-time consumption. Pricing pilots could be helpful to inform retailers about the likely strategies employed by consumers to shift their consumption, and ways to communicate messages effectively to different consumers
 - providing options to reduce price risks, such as through participation in controlled load programs, or offering a range of ‘smoothed’ tariffs
 - using targeted hardship programs and, in the future, electricity storage technologies to address the fears of vulnerable users who have no discretion in their power use, such as when power use is required for medical needs.

Many mass marketing and informational costs are fixed for a sufficient number of consumers, and could be more effective if pitched on a broader scale or, at least, on a community-by-community basis (akin to the transition to digital television).

A collective funding principle to pay for smart meters

Ideally, within a geographic region, a roll-out would be financed through a mandatory fixed charge included in network tariffs. Given meters have an asset life of around 15 years (and the communication module within the meter a life of around 7 years), the annual charge would only be a share of the total meter purchase price. Consumers could be given choices about how smart meter costs were reflected in their retail bills. In particular, while it is likely that retailers would broadly reflect the structure of the smart meter related network charges in their tariff offerings to consumers, they would be likely to also offer a number of other tariff structures and contracts (as per mobile phone plans). In addition, it is expected that retailers would offer different levels of price smoothing (in exchange for an appropriate risk management premium).

Regardless of how smart meter costs are reflected in consumers’ bills, there may be equity concerns for disadvantaged groups who are unable to offset the higher fixed costs through savings in their power use. There is already assistance to disadvantaged households with low incomes or struggling with their utility bills. For instance, lower-income households spend a much greater share of their income on electricity and face large problems in budgeting for quarterly billing (chapter 2). (Of course, with the roll out of smart meters that provide the ability to measure consumption remotely, much more regular billing could become practical.)

Given this, state and territory governments could develop criteria for any assistance to low income households for the cost of smart meter fixed charges that are similar to those already used to target financial concessions generally. It would be desirable that such criteria be consistent, at least, across the NEM and possibly also consistent

across utility services more broadly (draft recommendation 11.6). Any assistance should be transparent and financed in the most efficient way, such as through efficient general taxes or, if need be, as a small levy on the fixed charge applied to all electricity consumers.

The incidence of fixed smart meter costs can be distinguished from the equity and efficiency impacts of time-based pricing. As such, if low-income consumers are shielded from the fixed costs of a smart meter through targeted assistance, the potential for poor outcomes from time-based network tariffs for these consumers is significantly reduced. Trials find that low-income households tend to benefit from time-dependent charges if the cost of a smart meter is not included. For example, some studies suggests 80 per cent of low income households (which tend to have flatter load profiles) would be better off under time-based pricing without even altering their consumption patterns, and if responding to price signals, 92 per cent of low income households would be better off (Faruqui 2010).

Therefore, subject to passing a cost benefit analysis and appropriate consumer education beforehand, once a smart meter has been installed and retail price caps are removed (draft recommendation 12.3), there should be mandatory application of time-based network charges by distribution networks (draft recommendation 11.3). (Chapter 11 discusses the structure of these tariffs, transitional measures to ease the progression to cost-reflective time-based network tariffs, and specific assistance to vulnerable households.)

A region-by-region roll-out when the net-benefits are maximised

There are compelling grounds for a coordinated roll-out of smart meters by a single party on behalf of consumers. And, as discussed above, the costs should be paid for by consumers (with some exceptions). However, the concept of a universal roll-out need not be national or for a whole city. Rather, smart meters and the associated infrastructure could be installed on a universal basis within a discrete geographic region, subject to a cost benefit analysis to determine when it is most likely that the net present value of doing so is maximised. Likewise, coordination and overall management by a single party should not be taken to imply single suppliers of either the meters themselves or the contract installation of them. Competitive tendering for the capital equipment and installation services would be appropriate to minimise costs, irrespective of the party that ultimately bears any financial risk and responsibility for a roll-out.

It is unlikely that a cost-benefit analysis would justify the roll-out of smart meters in areas of the network where there is currently significant excess capacity.

Conversely, a smart meter roll-out in a particular region would be more likely to pass a cost-benefit test where the current network is approaching capacity, since that would maximise the potential for demand management to avoid costly network upgrades. Similarly, if existing meters are approaching the end of their asset lives, the additional cost of adopting smart meters would be lower compared to replacement of meters still well within their asset lives. In rural and regional areas of the network, there may be higher returns from smart meters associated with operational efficiencies for network businesses, including detection of supply failures, and remote connection, disconnection and meter reading.

In all cases, a key determinant of the potential benefits would be a requirement for tariffs to better reflect the real time-variant underlying costs of network services, since price difference between peak and off-peak use is a major driver of changes in consumer behaviour.

Who should implement a smart meter roll-out?

The obvious contenders for coordinating a universal, region-by-region roll-out would be distributors or retailers. The choice of one party over another would not necessarily preclude scope for competition in metering services, or dictate the ownership of meters and access to data and other sources of benefits. In particular, a party responsible for coordinating a roll-out would be expected to competitively tender for smart meter services.

The Commission considers that the division of responsibility and control between parties is finely balanced, reflecting compromises between alternatives.

Should retailers lead a smart meter roll-out?

As meeting customer needs is their core business, retailers may be in the best position to influence customer behaviour.

The availability of smart meters offers benefits to retailers, including the scope to add value to their traditional services by:

- more frequently billing their customers, and reducing the risk of default and the associated use of hardship provisions
- using detailed consumption data to offer tariffs and service plans that better meet customer needs and patterns of use

-
- offering load management programs and energy consulting services, such as automated solutions or direct load control of air-conditioners and other peak-heavy appliances
 - educating customers about how to get the best deal with the options that time variant pricing offers.

As stated by the chief economist of retailer AGL:

A smart grid, and what it can do for power system load factor, is a genuinely good story for our industry, and for our customers. (2012, p. 7)

To the extent that smart meters enable retailers to add value to their traditional service range, they may only need to partially transfer the costs of smart meters to their customers. However, the benefits retailers obtain from subsidising smart meters may be eroded if the consumer switches to another retailer, thus reducing the incentives for installing such meters. As summarised by Schächtele et al. (2011):

This business strategy suffers from a typical holdup problem as an investment risk results from the fact that consumers can easily switch retailers. Thus, retailers are hindered in covering part of the investment costs of consumers, which creates a major hurdle for market entry. (p. 11-12)

Imposing a sufficient lock-in period to ensure payback of benefits could potentially solve the pay-back problem, but faces some practical obstacles. Participants claim that the cost of acquiring customers, such as marketing and inducements, can already take years to recover. An incumbent retailer may have a greater capacity to pass costs on with less risk of losing market share (but any market power they hold could also reduce the likelihood of minimising the costs of a roll-out).

Another issue to be considered is that under current network and energy charging regimes, retailers take a margin on the total amount they invoice to final consumers, and thus generally gain more income the more power that consumers use. Ensuring that the structure of time variant network charges aligns the incentives of retailers with the objective of influencing consumers to move their consumption away from peak times will be an important part of a successful transition. Another argument that would not favour retailers leading a roll-out of smart meters is that a retailer may have a dispersed customer base that is not well aligned with the appropriate geographic region that is targeted to deliver the highest net benefit from a roll-out.

Even if retailers do not lead a smart meter roll-out, they would still need to be responsible for other investments and would be a crucial player in informing consumers. That would include the provision of consumer interface or add-on technologies and educational material about time-based pricing to assist customers in adjusting their consumption patterns to help manage their energy use and costs.

Indeed, it is in this line of technologies where the market role of retailers and scope for innovation and personalisation of services is likely to be most warranted. As stated by the Energy Retailers Association of Australia, because meeting and shaping consumer needs is a retailer's core business, they have the primary relationship with consumers and:

... are best placed to educate and inform consumers about the benefits of new technology and how these benefits align with consumer needs, such as energy cost management. (2012b, p. 7)

Distributors are the preferred candidate

A clear benefit from a distributor-led roll-out is their knowledge about the potential for network cost savings within given regions of their network. As network augmentation projects are generally lumpy and forward-looking, some localised network areas will have considerable spare capacity, perhaps for several decades. Accordingly, the returns from a smart meter investment to facilitate demand management in such areas would usually be low.

Other reasons supporting a distributor led roll-out include:

- network businesses benefit from operational efficiencies enabled through smart meters. However, to defray their existing costs of, for example, disconnections, connections and meter reading, a smart meter roll-out would have to be universal within a given region of their network
- many of the communication infrastructure options used to support a smart meter roll-out interact closely with the grid, which distributors control. Further, consistency of communication infrastructure and standards across the network should reduce costs. There are significantly fewer distribution companies to apply consistent standards across than there would be retailers
- the widespread adoption of time-dependent charging by retailers hinges on whether or not they face a time-dependent distribution network tariff for their customers' consumption. For this reason, tariff structures imposed by distributors would be a key trigger for a change to the business model of retailers
- this has been the model used to date in Victoria and in trials elsewhere.

On balance, and consistent with many others who have considered the options, the Commission supports a distributor-led arrangement for the roll-out of smart meters. Distributors would install meters and would own the technology and network management system within their area of operation (figure 10.4).

The Commission's assessment is consistent with other studies that quantify the potential net benefits from smart meter technologies. In particular, a distributor-led arrangement was also the assessment of the (then) Ministerial Council on Energy in their 2008 evaluation of four possible scenarios.¹⁴ A distributor-led arrangement similarly accords with the Victorian approach to their government-mandated roll-out. However, rather than offering a blueprint for successful implementation, the Victorian experience provides some important learning — principally:

- to estimate and manage costs extremely carefully
- to avoid a negative consumer reaction and educate consumers in advance about the reasons for the roll-out and the potential benefits of time variant pricing and demand management that smart meters enable
- with the close involvement of retailers, to ensure that time-based network tariffs are introduced following the roll-out (and that the range of retail tariff options and other potential advantages to customers are phased in).

Who should control the information hub?

Apart from allowing efficient pricing, smart meters provide a wealth of information and options to use that information for a range of uses by multiple market participants. For example, smart meters can be used to collect valuable information about each household's consumption patterns and, with add-on technologies to enable retailers to communicate prices to end-users, the price responsiveness of consumers can also be gauged. The use of this information would be subject to appropriate privacy considerations. In addition, with the agreement of end-users, smart meters allow the centralised implementation of sophisticated load management programs and can broaden the range of options to support emergency management of system reliability.

This raises the question of which party or parties should operate a central command and control hub of the smart meter platform (or whether any such universal coordination or central control is needed at all). This includes responsibility to implement and operate a single meter data management system (MDMS), which validates data and coordinates the communication of commands and information to and from meters (figure 10.4). Under a distributor-led roll-out, the communications infrastructure would be controlled and maintained by distributors, since it closely

¹⁴ The other three scenarios examined were a retailer-led roll-out, a centralised communications roll-out and a direct load control roll-out without smart meters. The benefits from a distributor-led smart meter roll-out are largely due to a wider range of communications options and synergies with network management.

interacts with their network functions. As such, distribution businesses would also operate the network management systems (NMS) — the IT platform that links to the communications system and interfaces with the MDMS.¹⁵

Some participants suggested that AEMO could operate a central MDMS as it is independent from distributors and already has some responsibilities for smart meters. (AEMO currently facilitates the communication of metering information between distributors and retailers.) The efficiencies and risks from having a single MDMS would have to be thoroughly analysed, but the option appears to have some merit. In particular, a central MDMS operated by AEMO:

- could deliver scale economies because it would spread the costs of fixed IT expenditures
- would allow prioritisation of communication flows and commands to smart meters from a variety of parties, including:
 - AEMO itself (to protect overall system security)
 - retailers (to manage both network and wholesale market events, billing to their customers, and deliver demand management services, such as direct load control, on behalf of their customers)
 - transmission and distribution businesses (to manage peak network events and implement load management according to contracted arrangements)
 - other approved third parties (such as demand aggregators)
- gives confidence that a distributor-led roll-out would not disadvantage other market players who might have legitimate reasons to access smart meter information and, with the agreement of customers, make use of the control and communication functions offered by this technology.

Currently, the transactions settlement and business-to-business system operated by AEMO is not a real time system. It would require an overhaul to be used as the seed of a central MDMS.¹⁶ Equally, however, an alternative where distributors each

¹⁵ As directed from retailers or other third parties acting on behalf of consumers, distributors would provide metering data services (with the information stored within the MDMS) and relay communications to smart meters. Given the market power that could potentially bestow on distributors, regulation would be needed to outline a distributor's obligation to provide these services at reasonable charge.

¹⁶ Currently smart meter data in Victoria is passed from distributors to retailers overnight. Unless they are designed to move data very quickly, the communications infrastructure, associated IT systems, and transfer of data between distributors and retailers, can create bottlenecks that generate delays. In the absence of real-time information flows in figure 10.4, customers could access their real time consumption by reading it from the meter directly, on a separate 'in-home display', or by using two-way 'zigbee' devices (a form of data communication using low power digital radio, similar to

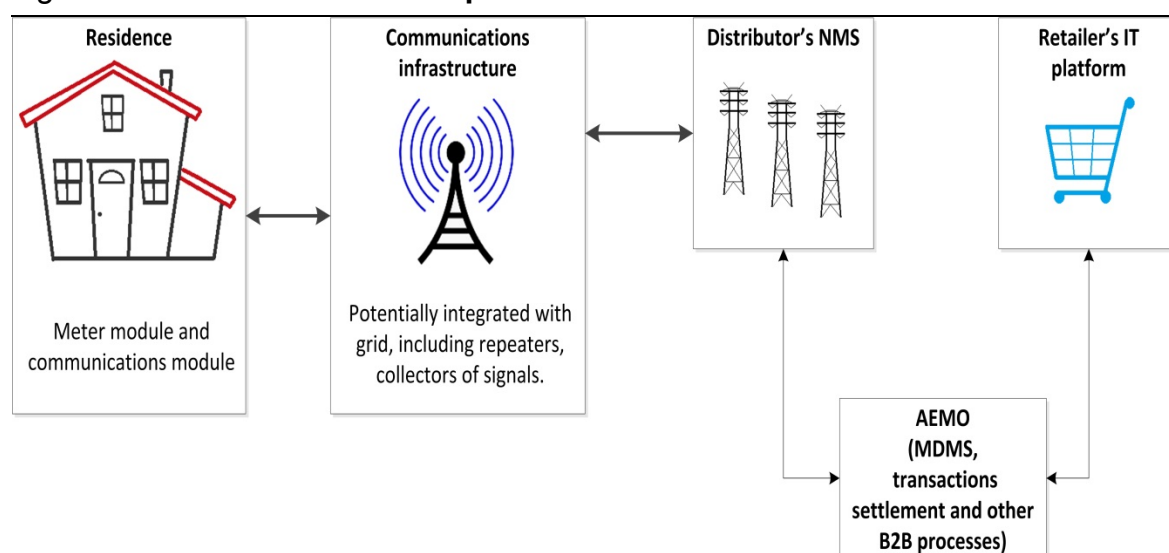
developed their own MDMS (as occurred in Victoria) would require sizeable investment. Appropriate empirical analysis would have to inform the relative costs and merits of either approach.

Any system would need to ensure consumer privacy and have appropriate security safeguards. In particular, the NER (and National Energy Customer Framework) should provide clear guidance about which parties are approved to access data. Currently, the NER assumes an arrangement where a consumer's agent, such as their retailer, can receive, relay and store data on behalf of their consumers. A central MDMS would assist retailers to have timely access to data (collected from multiple distribution businesses) allowing them to efficiently perform their exclusive role in interacting with and providing data to end-users.

The use of customer data by retailers would be an important aspect of their business, assisting with:

- the design and packaging of tariffs
- hedging strategies — managing price volatility — and efficiently charging for risk management services in accordance with different customers' load profiles
- targeting demand management services, such as direct load control.

Figure 10.4 The smart meter platform



Bluetooth) or an home 'gateway' (connecting their smart meter to the the internet). In principle, gateway and zigbee devices could be used by a retailer to initiate load control of appliances, without having to send the request through distributors.

How would approval of smart meters fit into the current regulatory framework?

Smart meters are unlike many of the conventional expenditure components of building block proposals (wires, trenches, poles and substations):

- (a) their success requires complementary policies, such as the phased introduction of peak pricing. By implementing smart meters, businesses, in effect, would be committing to introduce time-based prices and, in time, would face revenue implications from not pricing efficiently. In the fullness of time, this represents a significant shift in the existing paradigm of distribution businesses, and while some businesses may embrace such a change, others may be more reluctant
- (b) the effective use of smart meters may require the adoption of appliance standards and would certainly rely on retailers having aligned incentives to pass-through (or manage) more cost-reflective network charges. Each of these factors lie outside the control of the network business and would rely on decisions by governments. Further, governments themselves may seek to interfere in the benefits from smart meters, including by limiting the introduction of efficient pricing, hence creating risks for distributors
- (c) the current regulatory regime may undermine distribution businesses' incentives for their implementation. While smart meters can support more efficient network capital spending, the current regime may not provide efficient incentives to reduce capital expenditure (chapter 5). For example, the use of a revenue cap would act as an obstacle where smart meters are used to implement time-based network charges.
- (d) current retail price regulations may see retailers less than enthusiastic about time-based network charges, given the possibility of threats to their revenues, and the perception of general consumer resistance. The potential benefits from time-based network charges could be undermined by restrictions on retail pricing flexibility
- (e) it is desirable to plan and receive approval for their implementation over a longer timeframe than the current five year regulatory period — it is not clear that the regulatory regime (and the AER's application of it) would value savings beyond the current regulatory period
- (f) many benefits accrue to parties other than the distribution businesses ('spillover' effects). The current regulatory regime for distribution does not take into account these broader market benefits (although it is proposed that a Regulatory Investment Test for Distribution (RIT-D) would do so)

-
- (g) they are not (yet) customary investments for distribution businesses, and so may not be selected as a ‘non-network’ option
 - (h) there is significant uncertainty about the costs of roll-outs and about demand responsiveness (though trials have provided some information)
 - (i) the cost-benefit analysis underpinning a decision to proceed requires information from non-distribution businesses (such as transmission businesses)
 - (j) their introduction requires a level of customer acceptance, especially to ensure a smooth transition to their use for time-based network charges — a risk that distributors may be hesitant to take.

These factors indicate that:

- distribution businesses do not have fully aligned incentives to roll-out smart meters, and implement time-based pricing
- it is unlikely that the current propose-respond building-block model would function well in this regard.

A workable approach would need to take account of the peculiarities of smart meter investments shown in (a) to (j) above and sequence the roll-out to address the coordination problems affecting their deployment.

An important starting point is to address policy risks

State and territory policies lie outside the control of distribution businesses and pose considerable risks for investment in smart meters. The risks would be moderated by:

- (a) giving the AER a legal capacity to mandate roll-outs in given regions (subject to safeguards) throughout the NEM
- (b) removing existing state-based obstacles to time-based prices, such as the current moratorium in Victoria, retail price regulation in other jurisdictions, and the capacity of jurisdictional governments to exert influence through the licence conditions of network businesses
- (c) a commitment not to change the policy environment in a way that devalues smart meter assets (such as by re-imposing retail price regulations after a period of price flexibility).

Decision-making requires information

The AER would require detailed network planning information to approve smart meter roll-outs as would distribution businesses. A starting point to gather such

information would be from the proposed distribution annual planning report, as already proposed in the current rule change proposal with the AEMC — *Draft National Electricity Amendment (Distribution Network Planning Expansion Framework) Rule 2012*. The rule change proposes that distribution businesses publish an annual planning review covering an appropriate forward planning period of no less than five years, which should include forecasts of maximum demand for sub-transmission lines, zone substations and primary distribution feeders. Businesses would also be required to identify limitations within their network from forecast load exceeding capacity (and design fault levels) or relating to voltage regulation.

While some planning information is better than none, a longer-term plan (say of ten years) may be required:

- since the roll-out of smart meters has a long lead time, it would need to occur well in advance, if it were to make viable the option of deferring network augmentation
- to establish that the demand response from smart meters is sufficient to defer a network augmentation.

Given the central role of time variant network tariffs in efficiently moderating the use of peak network capacity by end-users, the AER and network businesses would also require detailed information on the responsiveness of consumers to higher peak charges. Chapter 12 recommends an increase in the innovation allowance of distribution businesses, which would help to facilitate the acquisition of such knowledge. Nevertheless, existing evidence from trials and experiments could help to guide early decisions until a larger pool of information accrues.

Similarly, evidence-based decisions would need to consider trends in smart meter costs, their technological capabilities and the likely network savings. Which party does this would depend on the choice of roll-out model (figures 10.5 and 10.6). There are also compelling grounds to reduce investment uncertainty (through early disclosure of roll-out costs by distributors for AER approval) and to increase the likelihood that the AER approves only prudent investments by benchmarking the efficient costs of smart meter roll-outs. Benchmarking should be based on domestic and, where possible, comparable international commercial experiences, and would be overseen by the AER — consistent with its capacity for such benchmarking under the Rules (chapter 8).

Can a commercially motivated approach work?

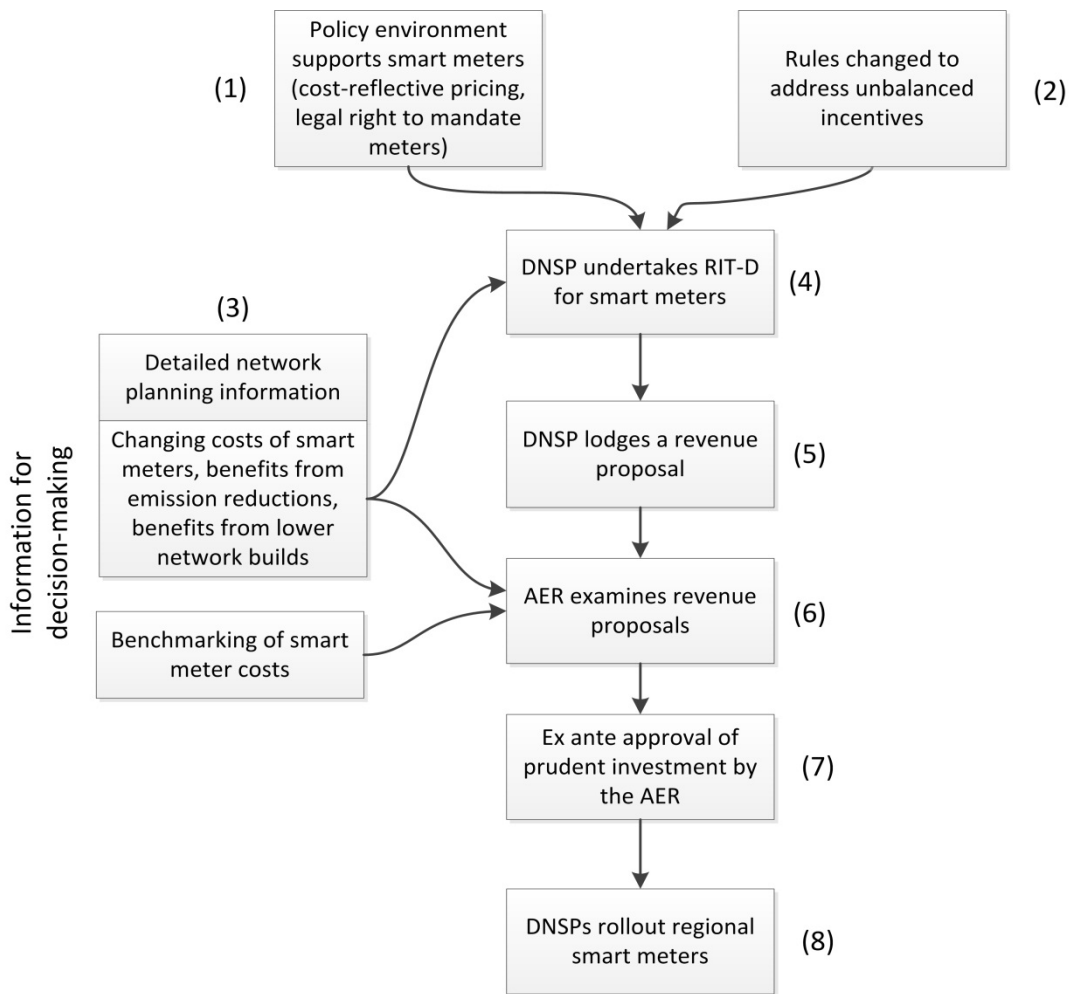
Allowing a commercially motivated decision by a distribution business about when and where to roll out smart meters has attractions. The distribution business has much information which should help it analyse when and where best to roll-out smart meters.

The process for investment approval would follow a model similar to the current revenue determination process (figure 10.5).

However, complementary incentive regulations are a key prerequisite for a commercially motivated approach and, as indicated earlier, for a raft of reasons it is not apparent that the incentives of distribution businesses to implement smart meters align with them assessing the net-benefits in an impartial and rigorous manner.

- There are major challenges in designing a regulatory regime that overcomes the current flaws (chapter 5), which are magnified when there are gains in future regulatory periods and spillovers to other parties. Any regime that achieved that goal would be complex (more so than the current arrangements), and may not have the predicted outcomes.
 - Indeed, even were a distribution business to propose a smart meter roll-out and demand management as part of a normal revenue determination proposal, it could subsequently decide not to proceed with the roll-out if it found alternative ways of meeting demand, or if demand forecasts proved incorrect. While this is generally a desirable outcome of incentive regulation, it may not be appropriate where the benefits of the investment extend beyond the investor.
- The introduction of a RIT-D could enhance the current regulatory regime's procedural attention to assessing the market-wide benefits from investments such as smart meters. However, the Commission notes that any such arrangement would have to overcome problems similar to those associated with the application of the parallel regulatory instrument for transmission — the RIT-T. In particular:
 - given the interested status of the party responsible for assessing the net-benefits, and that such an assessment necessarily relies on assumptions and informed judgements, ensuring estimates of the net-benefits are impartial and genuine is inherently a vexed issue (chapter 19).
 - as discussed in chapter 15, rigorous and independent cost-benefit analysis is necessary to provide assurance to governments and consumers that there is value in investments.

Figure 10.5 **A commercially motivated approach appears attractive**



Accordingly, there are reasons why (at least in any initial period of moving towards smart meter roll-outs and more efficient network pricing) it would not be appropriate to rely on distributors to bring-forward completely unbiased cost-benefit proposals for regulatory approval. Over the longer term, workable solutions to support the approval of efficient smart meter investments proposed by distributors could develop, especially when the effect of the package of reforms proposed by this report ‘washes through’. However, at this stage, there is a high risk that the incentives of distributors would not be appropriately aligned to support efficient investment proposals, suggesting that an alternative independent party would be best placed to assess the net-benefits of roll-out opportunities in constrained network areas.

Charging a central independent body with the task of rigorously assessing the net benefits of smart meters would develop a hub of knowledge and experience that could outweigh the initial informational advantages associated with distributor-led proposals. Further, were the AER to undertake such a function, it would marry with their additional responsibilities to support efficient time-based pricing (as outlined in chapter 11).

While attempts to adapt the current incentive regime for such purposes should not be abandoned, in the meantime, there are grounds for a planned approach that ensures, where justified, a region-by-region roll-out of smart meters (figure 10.6).

The key ingredients of a planned approach

Any planned approach would be subject to stringent cost-benefit analysis (CBA) undertaken by the AER (drawing on information from proposals put forward by distribution businesses and proposals or submissions as requested by the AER).

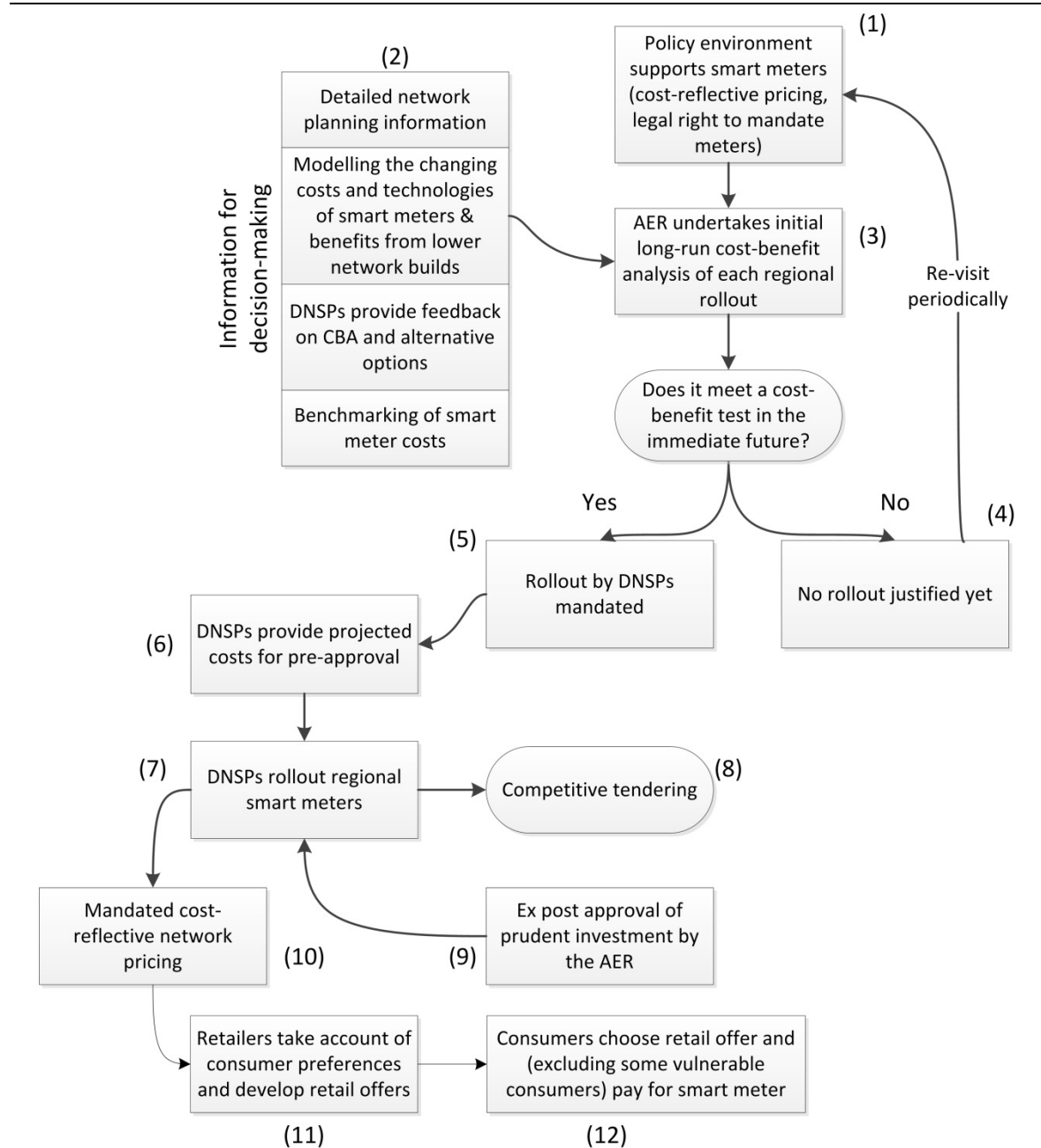
The AER's process for seeking proposals and supporting evidence from distribution businesses should be as streamlined as possible. The engagement of distribution businesses would be needed to support good outcomes, including smart meter roll-outs that target constrained network areas. As CBA involves assumptions and uncertainty, distribution businesses would have an important role in providing feedback on the AER's CBAs, which should also be publicly available.

The Commission seeks feedback on any improvements to the process proposed for smart meter roll-outs, and how distribution businesses can contribute to the Australian Energy Regulator's assessment of the costs and benefits.

The roll-out of smart meters should proceed when the AER assesses that the net present value of benefits are most likely to be maximised, or at least, after allowing for uncertainties, when the benefits would clearly exceed the costs. The evaluation of the net-benefits from smart meters should consider other feasible alternatives (technologies to implement demand management that do not rely on smart meters), including direct load control. The timing of approvals would not be constrained by existing regulatory determination periods.

Once meters were in place, it would also be mandatory that network businesses start to implement time-based charges. The framework of such charges, including assumptions about how they would initially be phased in and made more cost-reflective over time, would be implicit in the AER's CBA. Such judgements should be informed by evidence from pricing trials and developed in consultation with distribution businesses (taking submissions if desired), and made transparent at the time of approving the commencement of a roll-out. Otherwise, the inadequacies in the overall incentive regime might lead to implementing smart meters, but not to their efficient use. Moreover, where the AER mandates smart meters, subsequent regulatory determinations (including approval of demand forecasts) should take account of their expected network savings.

Figure 10.6 A planned process for rolling out smart meters



How would distributors recover prudent costs under a planned approach?

The AER could require businesses to roll-out smart meters, with either:

- an initial cost proposal by the business and ultimately an ex-ante determination by the AER of a revenue allowance that could recover their expected costs from customer charges. Businesses that were able to roll-out meters at lower than expected costs would retain the savings, creating incentives for cost minimisation, or;

-
- the AER ex-post approving a rate of return on prudent expenditure (effectively ‘rate of return’ regulation).

The former is preferred if the distribution business could be reasonably satisfied that the AER would not underestimate the required revenue to support smart meters, or that any such estimate is reasonably certain. However, even with the better provision of information (as discussed above), there is likely to be significant remaining uncertainty until many regional roll-outs have occurred. (The Victorian experience highlights the divergence between ex-ante and ex-post costs.)

Of the two options, the second appears to reduce business risk the most because it reduces the potential for the AER to set a revenue amount well short of the actual roll-out costs (and avoids the alternative risk of adding a sizeable risk premium to the estimated costs). Under this option, business should still provide the AER with a projected costing for provisional approval. That would reduce risks for business and avoid a situation where the AER subsequently determined that the business did not adhere to a commercial standard or chose an uncommercial technology. The use of competitive tendering would also encourage the efficient provision of smart meters, their installation and the provision of associated technologies such as enabling IT.

As an illustration of the uncertainties with the regulatory return of smart meter costs, the AER deemed that in Victoria, SP Ausnet’s roll-out was not prudent, a problem that would have been less likely had the AER given in-principle ex ante approval of the proposed approach. The AER considered that SP Ausnet’s adoption of WiMax (as the communications technology) involved a substantial departure from the commercial standard that a reasonable business would exercise under the circumstances. The AER adjusted the proposed advanced metering budget of SP Ausnet by around \$70 million (ACT 2012, Appeal by SPI Electricity Pty Ltd [2012]). The decision went to the Australian Competition Tribunal for merits review, which remitted some matters back to the AER for consideration. In particular, the AER is now considering the costs and delays if SP AusNet were to change to a different communications technology.

10.3 Other technologies to reduce peak load inefficiencies

Appropriately cost-reflective network prices that reflect the timing of consumption are an efficient tool to provide consumers with the flexibility to:

- determine the amount of energy they consume at peak times
- substitute between alternative power uses at peak times
- shift their consumption through time to make use of much lower off-peak rates.

Once instituted, such price signals also provide incentives for end-users (or retailers acting on their behalf) to invest in technologies that assist in responding to price signals.

A particular technology that can reduce peak demand and act as either a potential substitute or complement to smart meters (and efficient pricing) is direct load control.

How is direct load control achieved?

In the presence of smart meters

Many consumers facing cost-reflective prices will want to reduce peak load demand. They could do this by manually turning off electrical equipment, but that requires monitoring¹⁷ and simple oversights could expose consumers to large bills. In contrast, direct load control requires little ongoing effort for the consumer. If applied to air-conditioning, it provides a tool to balance price risks and in-home thermal comfort. In the presence of a smart meter and a compatible appliance, the costs of implementing direct load control are low — potentially costing around \$10-20 with the addition of a small piece of equipment to link with a compatible appliance (Wilkenfeld 2012).

...and in the absence of smart meters

Network companies (with the prior agreement of consumers) could still implement direct load control without smart meters and secure the benefits from reductions in peak demand. However, without price signals, consumer participation in direct load control programs requires incentive payments. For example, Queensland distributor, Energex, is offering a \$250 cash card for the installation of a load control device in new split system air-conditioners (which would allow Energex to defer more costly long-run network upgrades). However, such an approach is a blunt tool to secure the benefits of reductions in peak consumption, since standardised incentive payments bear no relation to different values consumers place on their peak consumption.

Ultimately, the most appropriate approach to implementing direct load control is an empirical question. At this stage, the technologies and their costs are rapidly evolving, which makes it hard to accurately assess the net benefits. Even if the cost of more rudimentary technologies were more cost-effective than smart meters over the short-run, it would be prudent to avoid locking-in technology solutions without

¹⁷ In addition, there are benefits from a central controller that rotates the use of power by appliances between households in a network area.

evaluating the stream of net-benefits (and that of alternatives) over the longer term. In particular, to the extent that direct load control might appear to provide a more immediate cost-effective means of reducing peak loads, its adoption would be likely to preclude the efficient uptake of smart meters (including efficient pricing and their other sources of benefit) for some time into the future.

Should demand response capability be mandated in selected new appliances?

Direct load control has significantly lower costs where the relevant appliance already incorporates the capacity to respond to remote commands. For example, enabling direct load control by retrofitting of an air-conditioner requires electrical re-wiring and could cost around \$1500 (Energy Australia and Transgrid 2009). However, with an appliance that was originally designed and manufactured to incorporate a demand response capability, direct load control could be achieved for only a small fraction of that cost.

The Australian Standard AS4755 *Framework for demand response capabilities and supporting technologies for electrical products* was published in 2007 to assist with this (box 10.3). Such a demand response capability could be applied to the manufacturing standard of numerous electrical devices, but is currently being investigated for air-conditioners, pool pumps and electric vehicles. An appliance that includes a demand response interface is frequently termed a ‘smart appliance’.

A small number of air-conditioners available on the market today are compatible with the AS4755 standard. These appliances can be activated for direct load control with the installation of a so-called Demand Response Enabling Device (DRED). The DRED can be:

- (a) a self-contained unit that receives remote signals to control load, processes them according to its settings, and sends instructions to the attached appliance
- (b) a ‘receiver’ attached to the appliance, with smart meters performing many of the other functions.

DREDs can be activated by a range of signals from the network provider or retailer, including those sent through power lines, phone lines, radio frequencies, and the internet. Passing signals through smart meters offers the potential for more sophisticated and personalised appliance responses and two-way communication with the network. It can also remove the need to roll-out a communication network exclusively for direct load control.¹⁸

¹⁸ Although, even where smart meters are not present, an entirely new communication system may not be necessary as some distribution networks already have a system present for hot water

A standard avoids the development of multiple, potentially incompatible technologies and could encourage the more rapid diffusion of direct load control. However, Australia imports most appliances. It is often costly for overseas manufacturers to develop products geared to the standard of a small market, like Australia. Moreover, unique Australian standards could act as an import barrier. In that vein, there are dangers in mandating the AS4755 standard, though there have been calls to do so (Wilkenfeld 2010, p. 2). There may be stronger grounds for encouraging (or even mandating) labelling that indicates that an appliance is compatible with direct load control.

Box 10.3 The AS4755 standard for demand response capability

The Demand Response AS4755 standard applies to the interface between a demand response enabling device and a variety of electrical products including air-conditioners, pump controllers, water heaters and electric vehicle chargers. Different parts of the standard apply to particular appliances and each is in different stages of development. The air-conditioning part of the standard is most advanced, although it is expected that all parts should be published in 2012. Compliance with the Demand Response AS4755 standard would feature on the energy rating labels of appliances.

Activation of demand response capability, including direct load control, requires connection to the demand response enabling device, such as a smart meter with the appropriate functionality or, if available, a home area network. Participants inform the Commission that the cost of such a connection is not expected to be large (likely to be around \$10-20 once compliance with the standard is more common) and may not require an electrician.

Voluntary compliance rates among appliance manufacturers are currently very low, which is not surprising given that the standard is new and evolving. By August 2011, only 2 out of roughly 78 potential brands of air-conditioning on sale in Australia had a demand response capability built in and ready to use, and a further 6 were compatible, subject to the addition of an extra part.

Source: Wilkenfeld (2011).

Nevertheless, reflecting on the package of reforms proposed by this Inquiry, the Commission recommends that the Australian Government (including with the involvement of Standards Australia) should undertake a cost-benefit analysis of mandating a ‘demand response capability’ into the manufacturing standard of suitable appliances. Such an analysis should appropriately focus on the option of direct load control of air-conditioners, but also consider the suitability of other

control that could communicate with DREDs for little additional cost. For instance networks in Queensland and NSW may be able to use their existing ability to send signals down power lines to operate DREDs on air conditioners.

future options. Any such initiative should be subject to a *careful* analysis and show why alternatives would be worse. That would include evaluating the likelihood and timeframe over which market solutions, or other similar international standards would develop and, hence, whether an accelerated adoption would yield net benefits in preparation for smart meters and mandatory time-based tariffs. The analysis should consider the costs of departing from international standards as it could be unduly costly to prematurely mandate a standard in the absence of international momentum in that direction.

DRAFT RECOMMENDATION 10.1

Distribution businesses should implement the roll-out of advanced metering infrastructure — so called smart meters — on a region-by-region basis within their network.

- ***Before any roll-out, the Australian Energy Regulator, drawing on the proposal and supporting evidence from the distribution business, should assess the net present value of costs and benefits, and be required to consider demand management options that do not rely on smart meters.***
- ***When the Australian Energy Regulator determines the optimal start date of the roll-out, the relevant distributor must submit a costing to the Regulator for approval and agree to an appropriate timeline for implementation.***
- ***Mandatory time-based network charges to retailers (draft recommendation 11.3) should be implemented once smart meters are installed, appropriate customer consultation and education has taken place, and retail price regulation is removed (draft recommendation 12.3).***

11 Moving to time-based pricing for the distribution network

Key points

- Under current pricing approaches, households and many businesses are not exposed to the much higher costs of supplying electricity during critical peak periods.
 - Consequent overconsumption of power during these peaks increases network investment needs, pushing up prices for customers. And those (often low income consumers) who use electricity less at peak times subsidise more intensive users.
- The broad case for moving to cost reflective, 'time-based', pricing for distribution network services is strong. As its use for some larger businesses exemplifies, it is practically feasible, with smart meters providing the technical means to extend the approach to households. Moreover, the pays offs from doing so are potentially very significant.
- However, there are many complexities and challenges in giving practical effect to time-based pricing. A coherent, iterative and consultative implementation process that harnesses the detailed knowledge of those at the coalface is therefore required.
- While not seeking to prescribe the pricing regimes that should emerge from this process, the Commission expects that network prices would be low for most hours of the day, but ramp up significantly during defined periods for critical peak demand events (such as a heatwave)
- Such changes would not give distribution businesses carte blanche to gouge consumers. Distribution Network Service Providers would remain subject to an overall revenue constraint.
- Given the broad end point is clear but the means and timeframes for getting there less so, the Commission has focused on ways to help ensure that there is an effective implementation process and conducive regulatory framework. It is recommending:
 - the Standing Council on Energy and Resources oversee and drive the process
 - some supporting changes be made to licensing arrangements for network providers and the National Electricity Rules
 - specific arrangements be employed to provide targeted assistance to vulnerable consumers adversely affected by the change in pricing approach
 - distribution businesses and energy retailers be required to demonstrate that they have engaged appropriately with their customers about the changes.

11.1 Introduction

As discussed in previous chapters, current ‘average’ pricing of the electricity network means that households and many businesses are not exposed to the much higher costs of providing electricity during peak periods.

The misalignment of costs and prices has three major undesirable consequences:

- The value of some of the consumption in peak demand periods that is encouraged by artificially low prices is likely to be much lower than its underlying cost.
- Since networks (and generation) must be built to meet critical peak demands, more investment in electricity networks (and in peaking generators) is required, pushing up average electricity prices for customers.
- Consumers who use electricity less at peak times cross-subsidise others. Often this will see low income consumers cross-subsiding higher income consumers.

The broad case for embodying a cost reflective, time-based component in prices for access to the electricity network — and especially the distribution component of the network — is strong.¹

The conceptual argument has long been recognised internationally (Joskow and Wolfram 2012). Reflecting this, there is already provision in the National Electricity Rules for the sorts of pricing approaches that would be required to give effect to time-based charges for access to the distribution network.

The approach is practically feasible. It is already employed for some industrial and commercial users, as well as in various non-electricity markets where demand and/or supply costs are time sensitive. And the smart meters necessary to implement time-based pricing at the household level are already in place in much of Victoria.

Most importantly, as established in earlier chapters, the pay-offs from introducing generally applicable, cost reflective, time-based pricing — hereafter referred to simply as time-based pricing — would be potentially large.

- Various empirical studies suggest that many electricity consumers will economise or shift the time of their consumption to avoid higher charges in peak periods (chapter 9). Reflecting such a demand response, AGL Energy estimated savings for households of \$1.6 billion from removing price regulation, installing

¹ In chapters 18, the Commission is proposing various changes to achieve more efficient charges, including over time, for transmission network services. However, the broad underlying goal is the same as for time-based pricing for distribution networks considered in this chapter.

smart meters and implementing a limited-form of time-based (network and retail) pricing (Simshauser et al. 2011). The Commission’s modelling likewise indicates that, provided there is a sensible transition process, there would be a sizeable dividend (chapter 9).

- Because low income customers tend to place fewer demands on the network during peak periods than those on higher incomes, generalised time-based pricing would unwind the cross subsidies entailed in the current ‘average cost’ pricing regime, and thereby improve equity in the broad.

It is therefore unsurprising that many major players are supportive of such an approach — the NEM policy maker (the AEMC) and all peak industry bodies representing the supply chain (the Electricity Network Association, the Energy Retailers Association and the Energy Supply Association). Consumer groups also acknowledge the benefits, though they want the risks managed for low-income consumers.

There will of course be many practical complexities and challenges in implementing widespread time-based pricing, not the least of which is ensuring that households and other consumers understand its implications and the means by which they adjust their power demands in response to it.

From a technical perspective, the absence of smart meters for households other than in Victoria suggests that an early focus could be on extending time-based pricing for industrial and commercial users. This would in fact provide a vehicle for ‘stress-testing’ the approaches employed and time for complementary reforms (chapter 12) to take effect, before extension of fully fledged time-based pricing to the household sector. The significant upfront cost of smart meters (chapter 9) further suggests that each roll out should be carefully coordinated and roll outs should focus initially on those segments of the household market where peak demand has the greatest impacts on network capacity requirements. (This would be consistent with the general thrust of draft recommendation 10.1 dealing with the roll out of smart meters.) But at the same time, there is little point in incurring the expense of installing smart meters and then waiting a long time before taking advantage of the opportunities they provide to much better signal the true costs of meeting critical peak demand in network pricing structures.

A further complicating factor is that the peakiness of demand, its duration and its timing vary geographically. Such differences should be reflected in a time-based pricing regime, though in a way that recognises the costs of introducing further complexity to tariff structures as well as the benefits. Scheme design and the surrounding regulatory architecture will also need to be cognisant of the role that retailers play (box 11.1) in translating time-based network charges into the prices

customers face; and of any impacts of hedging by network operators and retailers in muting the degree of price differentiation evident to customers (chapter 12). And changes to the structure of network prices will also need to be compatible with controls on the overall level of returns earned by providers.

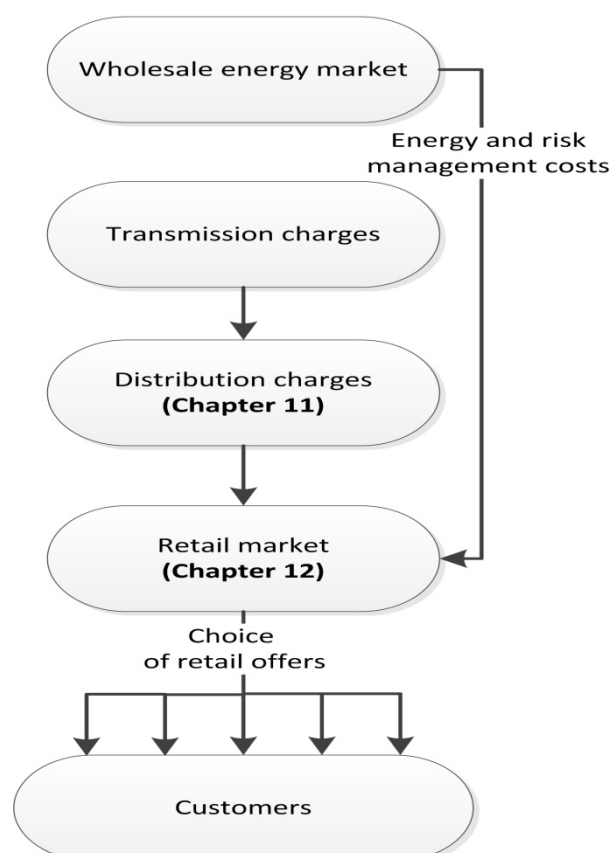
Box 11.1 The role of retailers

The price of electricity that is visible to households and businesses incorporates:

- charges for transmission and distribution network services, that are passed on to retailers
- wholesale energy and risk management costs from the spot and contracts market
- retail costs, including for customer procurement, billing services and a profit margin.

The retailer recovers these costs from customers.

As detailed in chapter 12, some barriers to competition and other factors might mute the incentives for retailers to reflect time-based differentiation in network charges in final electricity prices. Nonetheless, as discussed there, the Commission is confident that these incentives can be strengthened, such that time-based network charges would translate reasonably directly into the prices faced by many households and businesses.



The upshot of such practical complexities and challenges is three-fold.

First, the goal should not be to achieve the ‘perfect’ scheme that accords with some highly stylised text book model. Rather it should be to develop a workable, and generally acceptable, approach that provides a means to avoid much of the unnecessary cost that is currently incurred when catering for critical peak load demand.

Second the real world complexities strongly suggest that the detailed knowledge of those at the coalface should be harnessed in determining the parameters of a pricing regime that would best meet this objective. In other words, the regime should be developed carefully from within — rather than being externally imposed at the outset.

Thirdly, and related to the previous two points, there needs to be a coherent, iterative and consultative implementation process — both to put the flesh on the bones and to:

- ensure an appropriate degree of gradualism that takes account not only of the most efficient way to progressively roll out smart meters and the need for trialling of specific pricing menus, but also of the potential for the current stock of aged appliances to constrain efficient demand responses to time-based prices
- facilitate coordinated action in various other related areas — for example, in regard to the licence conditions for distribution businesses and those parts of the National Electricity Rules that have implications for time-based pricing
- help bring all of the various stakeholders on board by providing assurance that the reforms would be workable and beneficial
- ensure that customers understand the implications for their electricity bills and how they can moderate the impacts of significantly higher charges during peak periods
- ensure that there are well designed, targeted, mechanisms in place to assist those vulnerable consumers who would be disadvantaged by the changes, (or, if warranted on equity grounds, others facing a very substantial additional burden, such as those located in more remote areas where the costs of meeting critical peak demand are very high.)

Indeed, the latter is likely to be especially critical. While time-based charging would almost certainly have some very positive equity benefits, along with technological impediments, concern about the impacts on a sub-set of consumers has seemingly been an important reason for the limited use of the approach to date in both Australia and overseas.

The remainder of this chapter is concerned with mapping out in more detail how this process should unfold in regard to distribution businesses and some of the key requirements it should meet. Complementary (though somewhat different) pricing reforms for transmission networks are considered in chapter 18.

Finally, it is important to note that implementation of robust time-based pricing would not obviate the need to consider non-price options for helping to manage demand. For instance, the extension of load management schemes to harness the demand management potential of large businesses and industrial users could offer immediate benefits that are worth capturing — as noted in chapter 9, this option is being examined in a separate AEMC review.

11.2 How do distribution businesses currently price?

The National Electricity Rules require that distribution businesses recover approved revenue in excess of marginal costs in the least distortionary way possible.

However, as noted earlier, rarely are the costs of meeting ‘peak’ demand (box 11.2 for some definitions) well reflected in the network charges paid by households in particular. Pricing to reflect critical peak demand costs has been restricted to trial settings and any time of use (TOU) tariffs that are in place are typically much flatter than would be required to signal the escalation in network costs that occurs during critical peaks. Also, though charges for industrial and commercial users that incorporate a cost reflective peak and/or critical peak component — and sometimes other peak capacity charges — are becoming more evident, they are still not very widespread. The upshot is that distribution businesses recoup a high and excessive (AEMC 2012, p. 21) proportion of their fixed costs from non-peak usage charges (box 11.3).

This feature of distribution pricing structures appears to be driven heavily by an equity objective — and an underlying assumption that low-use (household) consumers are often low income. Several factors may help to explain this emphasis:

- State-owned distribution businesses are legally required to pursue certain social and equity obligations, and some refer to that motive in their pricing proposals.
- Now privately owned distribution businesses may still retain a public sector ethos — or legacies from the more direct controls that applied when they were government owned — that encourages ‘simple and fair’ pricing. (Some participants have informally asserted this.)
- Although state governments no longer regulate distribution revenues, they continue to set licence conditions and, therefore, have a pervasive influence on those businesses’ activities. Some privately owned distributors claim to be influenced by unwritten ‘guidance’ from jurisdictional governments, backed by the potential to write conditions into licence agreements or to restrict other aspects of commercial activity, if businesses do not fall into line.

Box 11.2 **Some terminology relevant to discussions of peak demand**

Terminology in this area is often confusing, ambiguous or overlapping. Accordingly, the meaning behind some commonly used terms is detailed below.

- Time based pricing/dynamic pricing/time dependent pricing — terms often used interchangeably to refer to prices that vary over time. The usually relevant time dimension is hours, but prices may also vary from season to season or from weekday to weekend.
- Cost-reflective pricing of the network — requires that prices signal the underlying costs of supply at the time of consumption. This requires that a peak period be defined sufficiently narrowly to ensure that the costs of peak capacity are recovered from consumption driving such investment.
- Time of Use (TOU) tariffs — a specific price structure where the day is divided into two to three consumption periods — ‘peak’ and ‘non-peak’ and sometimes ‘shoulder’ periods. A TOU tariff may additionally vary from season to season, depending on whether summer or winter peaks are more common. A feature of such tariffs is that the difference between peak and non-peak charges is not normally very large. This is because the ‘peak’ period tends to be very broad, with anything from 1000 to 3000 ‘peak’ hours over a year. The peak consumption in the NEM that drives significant additional network investment is much more short-lived — as few as 40 or so hours a year. Hence, the ‘peak’ price under a TOU tariff does not relate well to, or serve to reduce, the more intense peak consumption that is of concern in the NEM from a network investment perspective.
- Critical Peak Price (CPP) — a type of peak network price that is applied very narrowly to signal when demand is very high and supply very tight. A CPP is applied when a critical peak event is declared by a distributor. Where they have been applied for industrial or commercial users, it has usually been for a 2 to 6 hour window on 5 to 10 days per year. To assist the demand response and to avoid ‘bill shock’, customers are normally notified the day ahead of such an event and reminded 2 hours prior to commencement. Where applied, CPPs have been set to reflect the full cost (see below) of meeting a customer’s peak demand.
- Peak capacity charge — a charge for drawing on the network at a particular point in time (or, in the absence of a capacity meter, during a particular half hour). When applied to a very narrow peak, it is effectively a CPP (though in some cases ‘peak’ capacity charges have potentially applied to business users for over 3000 hours per year). The targeted peak may be related to an individual customer’s maximum demand, maximum demand at a substation, or the times of system peaks.

Peak charges based on Long Run Marginal Cost (LRMC) — the components of an overall tariff that reflect the marginal cost of supplying peak capacity over a period which is sufficiently long to make all network and other costs variable.

The ‘moratorium’ on time-based network pricing in Victoria is one such example of the latter, with its implementation more akin to a ‘gentlemen’s agreement’

unsupported by any specific written direction. Instances of more explicit directions include the South Australian legislation setting out derogations from the Rules for the 2010 distribution determination, and requiring that fixed supply charges not increase by more than \$10 per year. Similarly, in 2011, the Queensland Government directed its state-owned distribution businesses, Energex and Ergon Energy, not to pass on nearly \$100 million of approved additional revenue, consequent on a review by the Australian Competition Tribunal of a parameter involved in determining the companies' cost of capital. The Government indicated that, as the owner of the two companies, it would accept a lower rate of return on its equity.

To the extent that lower use consumers tend to have lower incomes, then shifting fixed costs into off-peak variable charges improves 'vertical' equity (the gap between rich and poor). In doing so, however, it creates scope for 'horizontal' inequities, as relatively low users (whether low or high income) are cross subsidised by people on the same income who are heavier users (and who therefore pay more due to the artificial inflation of the variable off-peak price). Taken together with the previously noted equity concern that the lack of time of use pricing may in an aggregate sense disadvantage low-income consumers, the collective equity impact of the current distribution network pricing regime is far from clear.

Importantly, equity objectives could be much more certainly pursued through instruments targeted explicitly and transparently at the needs of vulnerable (or otherwise unreasonably disadvantaged) consumers — such as through government-funded rebates for those who would otherwise face difficulty meeting electricity costs (or the fixed cost of a smart meter — chapter 10). Separately addressing legitimate needs of this nature would in turn mean that time-based pricing options (and other pricing reforms) could be examined through an efficiency lens, without the complicating and potentially confounding intrusion of equity considerations. Addressing equity issues as part of the pricing reform process — including the implications for the National Electricity Rules and the licensing of distribution businesses — is discussed in more detail in section 11.3.

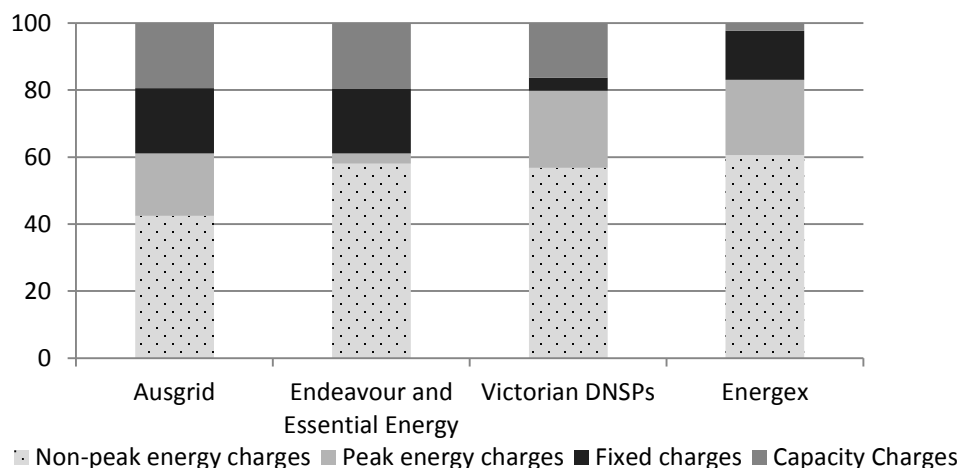
Box 11.3 How are peak network costs currently recovered in charges?

A significant part of the total revenues earned by Victorian and New South Wales distribution businesses is recovered through non-peak usage charges (between 40–66 per cent), with smaller proportions recouped from peak period and fixed charges. Moreover, capacity charges are mainly applied to large business users and, with ‘peak’ period ‘time of use’ tariffs far from universal across the household sector, for households the reliance on non-peak usage charges is higher again.

However, Ausgrid has recently sought to rebalance its tariffs, increasing the proportion of its revenue recovered through fixed charges and peak energy charges (Ausgrid 2012). Also, while its forecast revenue from capacity charges is projected to be much the same as in the 2008-09 to 2012-13 regulatory control period, there has been rebalancing of these charges across the customer base. A program to replace household accumulation meters with interval meters has assisted Ausgrid to rebalance their tariffs.

Revenue recovered by tariff component

Per cent, by NSW and Victorian distribution network service providers^a



^a Ausgrid, Essential and Endeavour Energy and Energex are based on forecast 2012-13 revenues, while Victorian distribution network service providers' revenues are based on 2010 revenues. Capacity charges apply to parties — mainly large businesses — that place a sufficient volt-ampere (VA) loading on the network infrastructure (which may require particular substation capacities).

Source: AER (2012); Ausgrid (2012); Energex Pers. Comm.

Do the National Electricity Rules facilitate time-based and other efficient pricing approaches?

Principles and requirements for determining network prices are set out in Clause 6.18 of the Rules. The content and wording of the clause provides both the scope and encouragement for distribution businesses to adopt efficient pricing regimes. Moreover, in assessing the pricing proposals of distribution businesses, the Australian Energy Regulator (AER) can pursue changes to non-compliant proposals.

However, as the current pattern of distribution network charges exemplifies, the existence of this clause has not precluded substantial divergences from efficient pricing approaches. Most notably, while sub-clause 6.18.5(b)(1) refers directly to Long Run Marginal Cost, it indicates only that businesses ‘must take [the concept] into account’ in deciding tariffs or charging parameters. The legal convention is that ‘take into account’ is a weak condition, even when preceded by ‘must’. The AER echoed this view, claiming that:

... the requirement to ‘take into account LRMC’ is very broad and provides limited scope for enforcement... (AER 2012a, p. 17)

A further more specific illustration is the seeming lack of discipline in the Rules on inefficient cross subsidies. Clause 6.18.5(a) requires that expected network revenue from each tariff class — a grouping of customers with similar consumption requirements and traits² and for which a distribution business faces a collective revenue constraint — lies between the avoidable and stand alone costs. In essence, the former represents the cost savings from not serving a particular tariff class assuming all other services continued to be provided; while the latter represents the much higher cost that would be entailed in serving the customers concerned through a dedicated set of assets. Unsurprisingly given the economies of scale and scope that characterise distribution, there is a large divergence between these lower and upper cost bounds. This means that within an overall revenue constraint, a wide mix of charging structures that potentially bear little resemblance to the true costs of supply will be compliant with the rules (table 11.1).

² In practice, such traits may include voltage supply level, volume of use, and nature of end use (domestic, business, commercial or industrial), but not geographic location (although the Rules would allow it).

Table 11.1 Some estimates of distribution network costs and charges

<i>Business</i>	<i>Tariff class^a</i>	<i>Standalone cost</i>	<i>Avoidable cost</i>	<i>Tariff revenue</i>
		\$m annual	\$m annual	\$m annual
ETSA (2012-13)	Major business	75	4	12
	HV business	84	3	36
	LV business	386	71	330
	LV residential	524	208	401
ETSA (2010-11)	Major business	72	4	9
	HV business	80	3	25
	LV business	367	67	247
	LV residential	499	198	303
Ausgrid (2012-13)	Sub-transmission	202	4	6
	HV business	558	6	49
	LV business and residential	2129	263	2047
Ausgrid (2010-11)	Sub-transmission	598	3	5
	HV business	880	5	38
	LV business	1384	58	672
	LV residential	1405	178	745

^a Sub-transmission is 33kV and above, HV is high voltage (nominally 5 -22kV), LV is low voltage.

Sources: ETSA Utilities (2010a, pp. 59; 2012a, p. 66); Ausgrid (2010c, pp. 44; 2012b, p. 34).

In making this observation, the Commission is not suggesting that the notion that prices should lie between avoidable and stand alone costs is of itself flawed. Rather, it is simply observing that the very large divergence between the two cost parameters negates any use this clause might otherwise play in compensating for the relatively weak nature of Clause 6.18.5(b)(1). Therefore, as discussed in section 11.3, the Commission considers that a tightening of Clause 6.18.5(b)(1) would be helpful in facilitating time-based pricing for distribution networks (as well as to support some other efficiency enhancing pricing reform).

11.3 Implementing time-based pricing

As noted at the outset of the chapter, the real world complexities of designing and implementing time-based pricing for distribution network services point to the need for a coherent, iterative and consultative implementation process — and one which harnesses the detailed knowledge of those at the coalface.

Given this, the Commission has focussed its attention on setting out some key requirements for that process to be effective and appropriately gradual, rather than

trying to prescribe in advance what sort of detailed time-based tariff structures would be appropriate. The Commission's expectation, based on time-based pricing regimes for industrial and commercial users (box 11.4), is that network prices would be low for most hours of the day and most days of the year, but would ramp up considerably for relatively short, critical peak demand events (such as a heatwave) that impose large costs on the system. Peak periods could also be defined more routinely (on a day-to-day basis, but, if so, the peak price would be considerably less than that at critical peaks).

Box 11.4 Time based pricing regimes for industrial and commercial customers

Current time-based pricing regimes for a relatively small number of larger industrial and commercial customers provide one indication of the sorts of tariff structures that might emerge where time-based pricing extended to othSP Aer customers, including households.

SP Ausnet's critical peak tariffs for businesses apply from 2 pm to 6 pm on a maximum of 5 days across the December to March period. These charges are uniform across the network, but vary across business customer classes from \$1.20 to \$3.20 per kWh (or more)³, compared to normal peak charges of 0.2 cents to 7.6 cents per kWh and off peak usage charges of 0.1 cents to 2.13 cents per kWh. SP-Ausnet uses long range weather forecasts to signal the likelihood of a critical peak day a week in advance, and gives one day's formal notice that critical peak event tariffs will apply.

While these schedules highlight that robust time-based pricing would involve some steep but short-lived price spikes (balanced by offsetting lower prices during other periods), considerable caution is required in extrapolating likely time-based tariff structures for households from what currently happens for some larger industrial and commercial customers. The different demand traits of household customers — and the additional degrees of freedom in setting time-based tariffs (within an overall revenue constraint) when all or most customers are in the net — are two considerations here. The important point is that it would be distribution businesses in consultation with the regulator, retailers and customers who would be best placed to determine what structures would be most appropriate.

However, it is the businesses that know their networks best and who (especially with the installation of smart meters) could quickly see how electricity consumers were responding to any particular tariff structure. It is therefore these businesses (in consultation with the regulator, retailers and customers) — and not an external party

³ As SP-Ausnet applies critical peak pricing based on the maximum kVA recorded during critical peak events, the kWh actually consumed may be less than this due to variation in consumption during these event and because of the power factor.

like the Productivity Commission — that should have responsibility for formulating detailed tariff structures, and iterations in them over time.

Importantly, this does not amount to giving distribution businesses carte blanche to gouge consumers under the guise of time-based pricing. As at present, tariff structures would still sit within an overall revenue constraint. The Commission is also proposing specific rule changes to ensure that the peak demand forecasts that bear upon revenue resets make appropriate allowance for the likely demand responses to time-based pricing (draft recommendation 11.4).

Likewise, giving those at the coalface responsibility for developing detailed time-based pricing structures is not to throw vulnerable consumers to the wind. As noted earlier, because low income or otherwise vulnerable consumers tend to be relatively low users of power at peak times, many would in fact be made better off by the rebalancing of prices under a time-based charging regime. And, as previously noted, to cater for those vulnerable consumers who would be materially worse off, the Commission is proposing specific, targeted compensation (see draft recommendation 11.6).

LRMC as the underlying basis for time-based network charges

While the Commission has not sought to prescribe in great detail what efficient time-based prices might look like, it is important that the broad basis for such prices is conducive to meeting the underlying objective — namely, achieving a reasonable alignment between the benefits and costs of distribution services at all times of the day and year. In the Commission’s view, and consistent with a wide body of economic and other opinion, this basis should be some measure of the LRMC of meeting peaks in demand.

In reaching this position, the Commission has been cognisant of the practical challenges in calculating LRMC, including current deficiencies in the data, and the fact that augmentations to network capacity are typically lumpy (see below). However, these are not insurmountable, and even proxies for LRMC are likely to provide a basis for prices that much better signal the true costs of meeting peak demand, than do the prices currently charged to most customers.

Unpacking the concept of LRMC

While the current Rules make provision for the use of LRMC, they provide little guidance on what it implies for time-based pricing of peak demand (or for other pricing purposes), or how it should be computed.

In essence, LRMC is the marginal cost of supplying a good or service over a period which is sufficiently long to make all costs variable. Hence, for a distribution network, it includes the cost of any additional infrastructure required to meet (a marginal increment in) demand. This feature is critical in setting prices that will:

- help to ensure that the overall value that customers collectively place on network augmentations to cater for peak demand — and hence their willingness to pay — exceeds the cost
- provide appropriate incentives for customers to economise, where feasible, on their use of power at peak times.

The latter in turn offers scope for major savings from deferring expensive new investment to meet typically short lived peaks in demand.⁴

As alluded to above, proxies for LRMC will sometimes be required. A case in point is the use of so-called Long Run Incremental Cost (LRIC) in circumstances where network investment is lumpy⁵. In this context, LRIC is essentially the cost of the minimum physically and economically viable network upgrade. In other words, it is still a measure of LRMC, though one that takes account of the realities of how network augmentation must and does proceed.

Also, and contrary to perceptions in some quarters, predicated time-based charges on estimates of LRMC that are sufficiently forward-looking⁶ is unlikely, of itself, to lead to undue volatility in electricity prices. This is more a problem that relates to short run marginal cost pricing in circumstances where high fixed costs have to be recouped at the point in the investment cycle.⁷

⁴ LRMC pricing could, in theory, be employed to recoup the entire costs of running a distribution network. However, the focus here is on using LRMC as the basis for setting a higher usage charge during periods of peak demand. The balance of a DNSP's revenue would then come from the sorts of two part charges that are currently levied — a base (non-peak) usage charge and a fixed charge set to, in combination, equate the expected revenue for a network business to its regulated revenue allowance.

⁵ 'Lumpy' network investments are large forward-looking investments with declining unit costs as the size of the investment increases.

⁶ Calculating LRMC (or more precisely LRIC) over a forward-looking interval smooths the forecast investment cost over the asset life. While the profile of returns under LRIC depend on assumptions about asset lives and depreciation profiles, and a dynamic price sequence results from the re-optimisation of estimates over time (as demand and capital costs change), the key point is that a distribution business should recover its investment costs over the lifetime of the asset.

⁷ The use of short run marginal cost pricing in these circumstances would, in essence, require the incorporation of a congestion component in charges when a network reached full capacity. Once these congestion charges had paid for the fixed costs of the existing network, new capacity

LRMC, once computed, could be encompassed in charges in a variety of different ways — including volumetric charges, access charges, charges linked to a customer's maximum demand, and targeted charges based on particular demands placed on particular parts of the network (such as a localised substation, neighbourhood feeder, sub transmission line, transformer or even interconnector). The precise nature and combination of these is again a matter for distribution businesses (in consultation with affected parties).

However, if LRMC pricing is to play an effective role in managing and moderating peak load demand, then the tariff structure must have a significant time-based component. The Commission's expectation is therefore that pricing proposals submitted to the regulator would involve significant and appropriate use of critical peak prices and (especially for businesses) peak capacity charges.

Issues related to the geographic differentiation of LRMC

The costs of meeting peak load demand and of augmenting the distribution network vary considerably across different locations. Significant differences of this nature should ideally be reflected in an efficient time-based pricing regime. As AEMC (2012) observed in its *Power of Choice Review*:

[Distribution businesses] have to ensure they provide sufficient capacity to meet demand in every part of their network, so differing demand patterns in different locations can have a substantial impact on costs. (pp. 63–4)

Where the network costs of supplying customers differs by location, the network tariff should likewise vary by location. (p. 206)

In this context, it is important to recognise that the peakiness of demand and the timing and duration of those peaks varies by location. Hence, an otherwise efficient time-based pricing regime that does not make provision for such variations will not capture all of the benefits potentially on offer. While the Commission has not been able to source comprehensive data on the nature and significance of localised network peaks, it has been told by distribution businesses that there is considerable variation. For example:

- in the outer suburbs of a large city, peaks may occur slightly earlier or later than in inner suburbs, largely reflecting differences in commuting distances
- in an area of the network with a high share of dairy farms, peaks tend to be early in the morning
- at a more aggregated regional level, peaks depend on the season.

would be installed and prices would fall sharply. This cycle would be repeated as the augmented network reached capacity.

The latter observation is supported by AEMC data showing that peaks are typically in summer in South Australia, Victoria, Queensland and NSW, and over winter in Tasmania (chapter 9).

Again, the precise way in which significant geographical differences in costs related to peak demand should be encompassed in time-based prices is a matter for DNSPs, the regulator and their customers. However, at a broad level, the Commission's expectation is that any geographic component of a time-based charge for access to the distribution network would reflect significant differences in:

- the rate of growth in peak demand and the timing of network peaks within discrete locations of the network
- the location of end users relative to generation sources and hence their call on distribution poles and wires during times of congestion
- the location-specific costs of expanding the network.

The Commission recognises that significant geographic differentiation in time-based charges could exacerbate equity concerns about the approach in the broad. However, most of these concerns could be addressed as part of the more general protection to be provided for vulnerable consumers (see draft recommendation 11.6). And though it is not clear why on equity grounds support should go beyond this vulnerable group, Governments could choose to provide more general assistance for all consumers in any areas where time-based pricing led to large increases in electricity bills. Like support for vulnerable consumers, any such support should be transparent and delivered efficiently (see below).

How good is the current information on LRMCs?

Accurately estimating LRMCs (or LRICs) in the distribution sector is intrinsically challenging. As SP AusNet observed:

... the long-run marginal costs of consumption are in a state of constant flux, and are affected by short and long-run factors, they are reliant on accurate consumption forecasts, accurate costing of capital and labour costs, accurate knowledge of the timing of required capital investment costs and perfect information of future technological advances. (SP AusNet 2012)

Moreover, network investments are not just related to peak load growth (or options to cost-effectively manage demand). The need to replace ageing assets, or to address externally imposed reliability requirements, are but two examples of other investment drivers. Indeed, because of economies of scope, investments will often

have more than one objective. In these circumstances⁸, the LRMC related to the peak demand component would need to be apportioned.

In this environment and within a system that has not been oriented to time-based pricing, DNSPs have tended to use compromised forms of LRMC for setting charges, which usually straddle a mix of marginal and average cost concepts. And as Turvey (2000, p. 26) has previously noted, data on maximum demands at different points in the distribution network — which might be used to geographically differentiate time-based charges — is lacking.

There are some published estimates of LRMCs relating more directly to peak demand. (see, for example, Colebourne 2010, ETSA 2012). However, they are clearly early work in progress and would be at best a starting point for calibrating the LRMCs necessary to implement a robust time-based pricing regime.

In the face of the current data deficiencies and the intrinsic difficulties of assembling such data, some might argue that trying to predicate a time-based charging regime on LRMC is simply too hard.

Yet there is widespread agreement that prices for electricity should play a much stronger role in managing demand. In moving from a system in which the need to collect, and the means to collect, time-focused cost data have been relatively limited, it is inevitable that new data will need to be assembled. And if this is the case, then the Commission sees no reason why the data effort should not target LRMC — the most appropriate basis for underpinning time base charging designed to deliver more efficient consumption and investment outcomes. As discussed below, the data that becomes available as a result of the much more widespread use of smart meters (draft recommendation 10.1) should be helpful in this regard.

Some related demand forecasting issues

Forecasts of peak (or maximum) demand are integral to the network planning and revenue determination process, and thereby to the timing and scale of network augmentations and the prices paid by consumers.

A phased introduction of time-based pricing will increase the complexity of the AER's task in this area. Specifically, there will be a need for forward looking adjustments that take account of the potential reductions in demand from more cost reflective prices at peak times, and the consequences for efficient levels of new investment and the revenues required to support them. As alluded to earlier, the

⁸ and also depending on the precise methodology adopted to calculate LRMC

Commission is proposing specific rule changes to give effect to this requirement (see draft recommendation 11.4).

This added dimension to the revenue determination process could, if undertaken well, provide a potentially powerful spur for DNSPs to implement efficient time-based pricing. That is, a distributor which did not implement time-based pricing to the degree provided for in the determination could expect to experience a revenue shortfall over the regulatory period.

There would also presumably be a concomitant financial incentive for distributors to invest in collecting and assembling data that would, over time, enhance the sophistication of estimates of the LRMCs of meeting peak demand. As well as benefiting distributors, through revelation via prices, it would assist the AER to progressively improve its demand forecasts. Indeed, this could be seen as a form of benchmarking — though one which targeted allocative efficiency by establishing a LRMC price benchmark, rather than technical efficiency which is the more usual focus of benchmarking exercises.

This interactive and iterative process would not, of course, eliminate the scope for errors in this component of the demand forecasts used by the AER in its revenue determinations⁹. Hence, there would be value in the AER improving its forecasting capacity, especially in regard to the price responsiveness of different groups of consumers at peak times. The progressive roll out of smart meters would help here — improving the quality of data on maximum loads across networks, allowing better identification of localised network constraints, and indicating the feasibility of reducing peak loads through pricing and other load management or distributed generation approaches. So too would the proposed increase in the innovation allowance for distribution businesses to fund trials of new time-based tariff structures and calculate demand elasticities (chapter 12). Indeed, trialling of new tariff structures, and carefully assessing their results, should be a key part of the process for progressively moving towards a robust time-based pricing regime (see below).

⁹ The Commission notes that planning arrangements would provide some insurance against overly optimistic estimates by the AER of the impacts of time-based pricing on demand. In effect, the processes used for network planning and the levels of investment required make provision for shortfalls between projections of maximum demand and actual outcomes. This would provide a cushion for forecasting errors.

Defining ‘peak’ demand

While the broad concept of peak demand is a relatively simple one, there are currently various obstacles to giving it appropriate effect within a time-based pricing structure.

At a high level, time-based prices will only do their job well if the definition of the peaks that underpin those prices is a good reflection of the actual peakiness of demand — demand that drives investment in additional network capacity. There is general agreement that current ‘time-of-use’ tariffs generally apply ‘peak’ periods much too broadly (and or frequently) to materially moderate peak network demand and the investment burden that comes with it.

However, as stakeholders’ differing expressions of the duration and frequency of peak demand exemplifies, there is no clear consensus on precisely how peak, and more particularly critical peak, demand should be defined. The fact that the frequency, duration and significance of peaks varies by location adds further to the definitional difficulty. Also, the demand response of customers to time-based pricing is explicitly intended to moderate peaks, as some customers economise on power or shift their consumption to non-peak periods. Hence, the definition of the peaks cannot be set solely on the basis of the current demand environment.

Given these complexities, the Commission has not sought to specify how peak demand should be defined within a time-based pricing regime. This again is a matter that should be determined by distributors in consultation with the other relevant stakeholders as part of the implementation process — though the Commission reiterates that peak period charges should be much more targeted to actual demand peaks than at present. As well as efficacy in meeting this targeting requirement, some key considerations in regard to definitions include:

- the capacity to translate definitions into relatively simple and understandable time-based tariff structures that facilitate the desired demand management approach
- the need to consider the costs and confusion that inevitably accompany changes in definitions.

The implication of the latter is that implementation of potential improvements in definitions (and hence tariff regimes) identified as experience with time-based pricing increases may need to be delayed. In other words, the usual cost-benefit trade-off should apply.

Some bottom lines on the use of LRMC pricing

The Commission recognises that, especially in the near term, there would be practical difficulties in operationalising widespread time-based pricing for distribution networks predicated on LRMC. In addition, lots of other things would have to happen elsewhere in the system to ensure that the pricing regime was well configured to meet the underlying demand management and investment objectives (see below).

Nevertheless, the Commission reiterates that it does not see these difficulties as insurmountable. The collection of better data, facilitated by the progressive roll out of smart meters, would ameliorate many of these difficulties. As would ongoing engagement between network businesses, retailers, customer representatives, the AER and State and Territory Governments on the means of iterating to a robust time-based charging regime. These considerations are reflected in specific recommendations below.

As discussed above, data issues and other considerations such as the lumpiness of network augmentation will have implications for how closely estimates of LRMC approach the conceptual ideal. But this would be no different from other markets where time-based pricing applies.

More importantly, a system that pays greater heed to the LRMC of meeting peak demand, and sets prices accordingly, would be a significant improvement on the current approach where these peak-related costs are spread across the tariff structure and therefore largely hidden from consumers. Put simply, if prices are to perform a role in managing demand and reducing the need to invest in additional network capacity, they must be considerably better targeted.

Facilitating an effective implementation process

Provision for external oversight

The general case for introducing time-based pricing for distribution networks cannot reasonably be disputed. Nor, in the Commission's view, is there any need to debate the underpinning basis for such pricing — it should be the LRMC of meeting peak demand. So the task ahead is to move as quickly and as smoothly to this end point as is possible given the various detailed matters that have to be resolved, and the complementary changes that have to be made elsewhere in the system. The latter include:

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- progressive and coordinated roll outs of smart meters which, in some parts of the NEM, may not occur for a number of years (chapter 10). Without the provision of real-time information to network businesses, people cannot be charged time-based prices
 - improvements to the incentive regulation regime to overcome biases against demand management and hence to move to time-based pricing (chapter 5)
 - wider use of weighted average price caps to further enhance the incentives for distribution businesses to price efficiently (chapter 12)
 - removal of retail price regulation that would otherwise frustrate time-based pricing and stifle retail competition and innovation (chapter 12), and their replacement with targeted and transparent means of support for vulnerable consumers
 - addressing the potential for reliability and network planning requirements to over-ride customer preferences and hence the strength of the demand management impact of time-based pricing (chapters 14-16).

There must also be arrangements in place to provide consumers with advance warning that critical peak prices are to be applied and thereby with the opportunity to adjust their power consumption. In some cases, people might request that the distribution business or retailer control their key power-using appliances — mainly air-conditioning — during these peak hours (‘direct load control’ (chapter 10)).

The Commission envisages that much of the necessary development work will occur within distribution businesses and the AER — including in regard to the methodologies for estimating LRMC and future demand within a time-based regime, supporting data collection, definitions of peak demand, and the options for translating all of this into network charges. Indeed, with a commitment to the introduction of time-based pricing and changes to the Rules that would penalise distribution businesses that do not take reasonable steps along this path (see below), businesses would have a strong commercial incentive to pursue necessary development work.

Distribution businesses and the AER would obviously need to consult on an ongoing basis. And both would need to engage with other key stakeholders during the process (including retailers, customer representatives and, through SCER, State and Territory governments).

The Commission is proposing some mandatory requirements in regard to engagement by DNSPs and retailers with their customers (draft recommendation 11.8). But these relate to the actual introduction of time-based network prices (and smart meter technology for households), not to the prior

developmental work. For this earlier stage of the process, consultation on an ‘as needs’, discretionary, basis would be most appropriate.

The Commission does, however, see the need for some external discipline on the development and implementation process. Given the complexities of the task, the many other changes in the system that have to occur, and the likely aversion of some stakeholders to moving expeditiously to time-based pricing, it is easy to see how the process could stall. Therefore, giving a suitably authoritative and knowledgeable external body responsibility for driving the process could be extremely helpful. Amongst other things, that body could establish realistic reform milestones and timelines, oversight progress against those timelines and, if required, bring stakeholders together to resolve specific road blocks or unduly slow progress in the broad. This would be akin to the valuable oversighting role that CoAG has played on a variety of major national reforms.

Indeed, the Commission considers that one of the CoAG family — the Standing Council on Energy and Resources (SCER) — would be well suited to this task. It has responsibility for pursuing priority issues of national significance in the energy and resources sectors. Among its specific functions are to facilitate national oversight and coordination of governance, policy development and program management in these sectors; provide national leadership on key strategic issues; and enhance national consistency between regulatory frameworks — all of which would fit well with a responsibility for driving the implementation of time-based pricing. However, in performing this oversighting task, it is important that SCER avoids prescriptive approaches that are not underpinned by a thorough assessment of benefits and costs.

DRAFT RECOMMENDATION 11.1

The Standing Council on Energy and Resources should be tasked with overseeing the progressive implementation of cost-reflective, time-based pricing for electricity distribution network services, predicated on the long run marginal costs of meeting peak demand. Amongst other things, the Council should:

- ***following consultation with key stakeholders, set timelines for the various steps in the development and implementation process, having regard to:***
 - ***the Commission’s specific proposals in relation to this process (draft recommendations 11.2 to 11.7)***
 - ***progress in making necessary changes elsewhere in the system***
- ***monitor compliance with those timelines***
- ***address any areas where greater engagement between key stakeholders (distribution businesses, retailers, state and territory governments, the***

Australian Energy Regulator and customer representatives) would assist the expeditious implementation of the new pricing regime

- *if and as necessary, take specific steps to address implementation delays.*

The Commission has also identified some more specific changes that would contribute to the implementation of an efficient and sustainable time-based pricing regime. (Complementary reforms, that would help ensure that time-based pricing provides a significant dividend, are discussed in chapter 12).

An NEM-wide licensing regime for network providers

One specific step that could be taken reasonably quickly to facilitate the implementation of time-based pricing for the distribution network would be to establish a single set of licence requirements for all network providers operating in the NEM. Such a change would of course have wider benefits — including for the transmission component of the NEM and by assisting the introduction of:

- an NEM-wide reliability framework (chapter 14)
- a common and efficient approach across jurisdictions to the provision of assistance to vulnerable consumers (see below).

More specifically — and in combination with making the AER responsible for enforcement — a NEM-wide licensing regime would reduce the risk that the pursuit of non-efficiency objectives by state and territory governments could frustrate the introduction of cost reflective, time-based pricing.

In making this observation, the Commission is not questioning the right of jurisdictions to pursue equity and other non-efficiency related objectives linked to the provision of electricity services. But in the past, this has sometimes occurred in ways that have been inimical to the longer term interests of consumers overall and the wider community. One example is the implementation of reliability standards where the benefits for consumers (as reflected in their willingness to pay) are seemingly considerably less than the costs involved in upgrading networks (chapter 14). And of more direct relevance to time-based pricing are the previously discussed instances of jurisdictional governments intervening implicitly or explicitly to modify charging regimes for equity reasons. This is in conflict with the principle that has been endorsed by all Australian governments that support for low income or otherwise disadvantaged consumers should be provided through targeted and transparent instruments.

While individual state and territory governments retain discretion over the licensing requirements for network businesses in their jurisdictions, there remains a risk of

actions that would be prejudicial to the efficient implementation of time-based pricing. Indeed, in this context, the shift in responsibility for enforcing compliance with licence conditions to the AER is no less important than a move to common requirements — particularly in jurisdictions where governments also own the network providers.

Against this backdrop, the Commission is proposing that a single set of NEM-wide licensing requirements replace the current state and territory provisions, with these new requirements being incorporated in the Rules.

These common requirements should be developed by state and territory governments under the auspices of the SCER. Importantly, the Commission's expectation is that a robust and transparent process (similar to the use of a Regulatory Impact Statement) would inform the development process to minimise the possibility that there would be gravitation towards the most stringent (and costly) jurisdictional provisions in each area. The Commission further notes that the development of aspects of these new requirements might sensibly be tasked to the AEMC, who could undertake a framework review to assist the process of developing national conditions. It is also important that jurisdiction-specific licence conditions are only included where the framework review (which would effectively act as a regulatory impact statement) can demonstrate a clear and cogent basis for such divergence.

While the AER would be responsible for enforcement of the new licence conditions, it could sensibly seek advice on technical issues from the AEMO or state-level regulators. Provision could also be made for the AER to delegate responsibility for assessing compliance with particular licence conditions to an independent jurisdictional regulator, but not to a state or territory government.

The Commission has not sought to identify all of the particular matters that should be encompassed in the new licensing regime. However, reliability, the provision of assistance to disadvantaged customers or any requirements to provide non-commercial services, and technical standards and safety requirements would be some of the matters to be addressed.

Below, the Commission has made some specific proposals relating to those consumers requiring support to meet higher bills following the introduction of time-based pricing, or to help pay for the cost of smart meters. Suffice to say at this point that the criteria governing that support — or support provided through the provision of non-commercial services — should be explicit in the new licensing requirements. Additionally, the requirements should specify how such community service obligations are to be financed (see below).

The Commission notes that preparatory work would have to occur to develop national criteria that identify customers in need of support and a uniform approach to funding that assistance. This should not delay the development of national licence conditions. As such, until uniform criteria and sources of funding are developed, each state and territory government would continue to be responsible for targeted financial support to address the affordability of electricity.

DRAFT RECOMMENDATION 11.2

The Standing Council on Energy and Resources should initiate a process to establish a uniform set of licence conditions for all transmission and distribution network businesses in the National Electricity Market. The Council should task the Australian Energy Market Commission to undertake a framework review to assist that process.

The development of a uniform set of licence conditions should have regard to the Commission's proposed changes to the reliability framework (draft recommendations 15.1 and 16.1) and should not in any way conflict with, or impede, the implementation of that framework.

The uniform licence conditions should be included in the National Electricity Rules and replace the current state and territory licence conditions.

It may not be immediately feasible to develop standardised provisions governing technical standards and safety, though these should ultimately be encompassed in the national set of licence conditions.

The justification for any jurisdiction-specific conditions included in the new licensing regime should be clearly and cogently spelt out in the supporting framework review.

Before incorporation into national licence conditions, preparatory work would be needed to develop a common approach to the identification of customers in need of special support to meet their electricity bills or pay for smart meters (draft recommendation 11.6), but:

- *pending agreement on appropriate national criteria and approaches to funding, each state and territory government should continue to be responsible for targeted financial support to address affordability.*

The Australian Energy Regulator should be responsible for ensuring compliance with the new conditions and would have the authority to:

- *issue and retract licences*
- *seek advice from relevant agencies on any technical matters relating to compliance assessment.*

Provision could also be made in the Rules for the Australian Energy Regulator to delegate responsibility for assessing compliance with particular licence conditions to a relevant state-level regulator.

Tightening and augmenting aspects of the Rules

The Rules bearing on the use of LRMC for price setting are not emphatic about the desirability of using this benchmark, so much as permissive (section 11.2). The Commission's assessment is that several clauses could weaken the discipline on DNSPs to employ the approach.¹⁰ However, the key clause in this regard is 6.18.5(b)(1) which, as noted earlier, requires only that LRMC be 'taken into account' when determining tariffs. This allows the AER to approve a tariff consistent with LRMC, but does not compel it to require that a business sets prices on this basis. Commenting on the current rules, the SCER noted that the way in which:

... the regulatory regime administered by the AER incentivises distributors to implement [efficient time-based] tariffs is unclear. Absent particular incentives to do so, there is no particular reason to expect that they will set tariffs in such a way to maximise the impact on peak demand, although nothing prevents them from doing so. (SCER 2011, p. 12)

While this vagueness in the Rules persists, it is unlikely that the AER could require adherence to genuine LRMC methodologies, putting at risk the transition to cost reflective, time-based, pricing — or at the very least detracting from the quality of the pricing regimes that emerge.

The timing of a rule change to address this problem would of course be dependent on progress in getting in place the many other preconditions to enable the commencement of time-based pricing. This timing might reasonably be the subject of discussions between stakeholders and the SCER as part of the latter's proposed oversighting responsibility (see draft recommendation 11.1). But it is an important change to be made at some point. In essence, clause 6.18.5(b)(1) should require that time-based pricing be predicated on LRMC, with the task of the AER being to determine whether pricing proposals are reasonable from this perspective recognising the practical computational challenges.

¹⁰ These include clause 6.18.3(d)(1) relating to the efficient allocation of customers to tariff classes; clause 6.18.3(d)(2) relating to the avoidance of undue transactions costs in defining customer classes; 6.18.5(a) requiring that revenues recouped from each tariff class lie between incremental and stand alone cost; 6.18.5(b)(2)(i) relating to the transactions costs associated with a tariff or charging parameter; and 6.18.5(b)(2)(ii) relating to the capacity of consumers to respond to price signals in a tariff.

At some point in the transition process, the rules governing the setting of tariff classes (clause 6.18.3(d)(1)) should also be tightened. As it currently stands, this clause refers to the need to group customers on an economically efficient basis, but again on a ‘have regard to’ rather than a ‘must’ basis. Also, it does not explicitly refer to the geographic dimension of efficiency in regard to the setting tariff classes — an omission which has the potential to impede variations in time-based prices across regions to reflect significant differences in the cost of meeting peak demand. The Commission is therefore proposing a remedial amendment to address these shortcomings.

Finally, the rules will also have to be amended to give the AER the power, when assessing pricing proposals, to consider whether a business’s forward peak demand forecasts make reasonable provision for the impacts of time-based pricing in constraining demand. Otherwise, the benefits of the approach in delaying or deferring investments in peak load capacity will be diminished or even lost. As an adjunct to this, and in keeping with the earlier discussion on these matters, the AER will need to develop its demand forecasting capacities.

DRAFT RECOMMENDATION 11.3

When the process of implementing cost-reflective, time-based prices for distribution network services is sufficiently advanced to reasonably allow for a tightening of relevant clauses in the National Electricity Rules:

- *clause 6.18.5(b)(1) should be amended so as to ensure that time-based tariffs are determined by (rather than ‘take into account’) a reasonable estimate of the long run marginal cost for the service concerned*
- *clause 6.18.3(d)(1) should be amended so as:*
 - *to ensure that the grouping of customers for the purposes of setting time-based tariffs is based on economic efficiency (rather than ‘having regard to’ it)*
 - *to make it explicit that significant differences in the long run marginal cost of meeting peak demand between locations and across customer groups should be reflected in network pricing structures.*

DRAFT RECOMMENDATION 11.4

When the process of implementing cost-reflective, time-based prices for distribution network services is suitably advanced, the requirements governing assessments by the Australian Energy Regulator of pricing proposals by distribution network service providers should be amended such that the regulator:

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- *can only approve a distribution business's peak demand forecasts if they include reasonable forward estimates of the likely demand response to time-based pricing*
 - *subject to the above condition, must approve any reasonable estimate by a distribution business of the long run marginal costs of meeting peak demand.*

To support these changes, the Australian Energy Regulator should develop a capacity to model demand responsiveness to time-based pricing.

Guidelines to support methodological development and data collection

As discussed above, the Commission sees much of the responsibility for methodological development and data collection residing with DNSPs. Such development and data collection would in turn be informed and assisted by trials and experiments with time-based pricing as part of the phased implementation process (chapter 12). To support this testing process, the Commission is proposing an increase in the Innovation Allowance for distribution businesses (draft recommendation 12.2) — subject to the proviso that this additional revenue stream funds specific projects, developed in close cooperation with retailers, that shed light on:

- the responsiveness of customers to time-based prices and/or
- the means to introduce time-based pricing that would help to empower consumers to respond effectively and to minimise initial uncertainty and confusion.

The Commission also sees a potentially significant benefit in the AER developing guidelines on key methodological and definitional issues to underpin the operation of the new regime. The area in which guidelines would be most helpful would be the methodology for computing the LRMCs of meeting peak demand. Such guidelines might reasonably specify factors that should be included in the estimation of LRMC and an approved methodology or methodologies for that estimation (including, as previously noted, the use of LRIC for lumpy investment costs). For obvious reasons, the guidelines should be developed in consultation with network businesses and should not be overly prescriptive. This is an area where it is important that the AER remain open to the use of different approach depending on the particular circumstances of a network business. Indeed, the Commission's expectation is that the guidelines would require iteration as experience with time-based pricing, and calculating the costs of peak demand, increased. The Commission further notes that a change in the current Rules would be required to enable the AER to publish guidelines of this nature.

The AER should also have the scope to publish binding guidelines about efficient tariff structures, the definition of network ‘peaks’ and associated critical peak pricing events. Establishing sound approaches in these areas at an early stage of the implementation process is likely to be very useful in buttressing the bona fides of time-based pricing as a means to curb peak demand and reduce network infrastructure needs. Again, however, it is important that any such guidelines be developed in consultation with relevant stakeholders, not be overly prescriptive and formulaic, and provide scope for iteration over time.

DRAFT RECOMMENDATION 11.5

Clause 6.2.8(a)(3) of the National Electricity Rules should be amended to:

- ***require the Australian Energy Regulator to publish guidelines on the methodology or methodologies that are appropriate for estimating the long-run marginal costs of meeting peak demand, and the factors that should be encompassed in those estimates***
- ***give the Australian Energy Regulator the authority to publish binding guidelines about efficient, time-based tariff structures, including definitions of ‘peak’ pricing events.***

These guidelines should be developed in consultation with the relevant stakeholders and should be improved over time as the implementation of time-based pricing progresses.

The Commission further notes that the AEMC is currently evaluating a rule change proposal that includes a requirement for distribution businesses to publish an annual planning report covering the subsequent five years, with information provided at the sub-transmission, feeder and zone substation level. This could help to overcome some of the current gaps in the data relevant to estimating locational differences in the cost of meeting peak demand, and thereby to incorporating a geographical dimension in future time-based prices. (This proposed rule change, and the grounds for extending the required forecast beyond five years, are discussed in chapter 10.)

Addressing affordability and equity issues

The distributional effects of time-based pricing

In broad terms, cost reflective, time-based, pricing may see DNSPs recoup a significant proportion of their total revenue from those drawing on the system during peak demand periods. Other things being equal, they will then be less reliant

on revenues from fixed charges and usage tariffs during non-peak periods. If this rebalancing is appropriately translated into retail electricity prices:

- those who continue to use large amounts of power at peak times will face considerably higher bills
- those who were already low users at peak times, or those willing and able to respond to the price incentive to economise on peak period consumption, will experience lower bills — or at least lesser increases.

As noted earlier, low-income households tend to be relatively low users of peak load power. Hence, as a group, they could well benefit from the removal of the current cross subsidies from those who put relatively small demands on the network at peak times to those whose demands are larger. In its recent submission to the Senate Select Committee Inquiry into Electricity Prices, the South Australian Council of Social Service (2012, p.16) said that:

- Low income households have less peaky demand because their houses are usually relatively small, air conditioning penetration is lower, and where airconditioners are fitted they tend to be smaller.
- As a result of this less peaky demand, the introduction of cost reflective retail and network pricing would see average bills for these households fall by 10 to 20 per cent — implying ‘that it is a reform worth pursuing.’

Even so, it is almost inevitable that some low income households, or otherwise vulnerable consumers, would be among those disadvantaged by the introduction of time-based pricing (and by the associated recoupment of the costs of smart meter installation).

The efficient pursuit of equity objectives

Equity as well as efficiency matters for community wellbeing. Hence, the Commission recognises that, in pursuit of equity objectives, governments may reasonably seek to intervene to improve the affordability of electricity services for some consumers — and by implication, the cost of the distribution network charges they incur.

However, such objectives can be achieved in a variety of ways, some of which are more efficient than others. Using the most efficient means to address genuine equity or hardship issues will minimise the costs imposed on those not in receipt of support, and thereby deliver a better outcome for the community as a whole.

The key here is to use measures that explicitly target vulnerable (or otherwise unreasonably disadvantaged) consumers. Indeed, as the Commission discussed in its recent report on urban water, targeted mechanisms are already employed for utility services (box 11.5). In contrast to cross subsidised usage charges, such targeted instruments do not lead to inefficient demand responses by consumers who do not require support. And if well designed, targeted support may also have relatively little impact on the demand responses of recipients.

As well as concessions and rebates, an appropriate suite of instruments for helping vulnerable consumers to accommodate time-based pricing might include targeted subsidies for demand response compatible air-conditioners, or for improving the thermal efficiency of their dwellings (chapter 10). These could be funded from general government revenue or a small increase in the fixed access charge. More broadly, there may be a case for some shift away from service-specific support to assistance via the Australian Government tax transfer system (see below).

Some other options that have been suggested would clearly be inappropriate.

- Exempting all low income groups from time-based prices, or making it optional for all consumers — as proposed in a recent report by Deloitte (2012) for the Victorian Department of Primary Industries — would significantly negate or eliminate the sort of demand response that such prices are intended to induce. Thus in the latter case, those currently putting sizeable demands on the system at peak times would presumably opt to retain the inefficient, and often inequitable, subsidies they currently receive. In the former case, a blanket exclusion of low income consumers would deny many of them the savings that time-based pricing would otherwise bring.
- The same sorts of considerations also militate against completely eschewing geographic differentiation in time-based prices to assist vulnerable consumers in parts of the network where peak demand is expensive to meet. Indeed, appropriate and transparent price signals might be particularly valuable in high cost areas to encourage exploration of potentially more economical alternatives for meeting consumers' needs at peak times, such as distributed generation (chapter 13). That said, the appropriate level of geographic differentiation and the way it should be introduced are complex matters on which the Commission is seeking further information (see below).

Box 11.5 **Utility concessions and rebates**

In addition to welfare measures provided by the Australian Government (and funding for concessions under the National Partnerships Agreement for utility concessions to pension card holders), state and territory governments provide a variety of concessions and rebates to households for their electricity and other utility services. Although administered by state and territory governments, eligibility for the latter tends to be linked to commonwealth concession cards, with over 5 million card holders (including 3.6 million Pensioner Concession Card holders).

Energy concessions and rebates are generally worth in the order of \$200 to \$400 a year to the recipient, although in Victoria the amount of assistance is determined as a percentage of the electricity bill (AEMC 2012, p. 23). Emergency payments may also be available through community welfare organisations. Such forms of assistance can be provided directly to a consumer as a rebate, or indirectly through their retailer as a discount on their electricity bill. As well as differences in value and form, eligibility requirements also vary across jurisdictions.

In its report on the urban water sector, the Commission (PC 2011c) analysed the role of concessions and rebates in addressing affordability issues for vulnerable consumers. It concluded that compared to delivery through cross-subsidised usage charges, these forms of assistance can better target those in genuine need and involve smaller costs to efficiency (see text).

Current arrangements for delivering support must be improved

In view of the potential for poorly configured support for vulnerable (or otherwise unreasonably disadvantaged) consumers to undermine the effectiveness of time-based pricing, the Commission considers that robust criteria for such support should be developed — and, as noted earlier, incorporated in the new NEM-wide licence conditions for network providers (see draft recommendation 11.2).

Ideally, eligibility criteria would principally target support at households who have both low income (or are otherwise financially vulnerable) *and* face inherently high supply costs. In practice, neither existing concession nor currently operational definitions of ‘vulnerable’ closely accord with these requirements.

More generally, as noted by Australia’s Future Tax System Review Panel (2009) and in the Commission’s urban water inquiry (2011c), current concessions:

- are utility specific, with a confusing array of assistance collectively available for essential services

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- employ a range of approaches of varying effectiveness and administrative efficiency, and with differing impacts on economic efficiency and equity in the broad
 - tend to treat holders of Pensioner Concession Cards (including aged pensioners) more favourably, despite some pensioners receiving higher incomes than other vulnerable groups.

But while the case to improve the delivery of financial assistance to households facing long term difficulty affording utility services appears a strong one, the best way forward is less clear — with the choice in reality being between imperfect alternatives.

Accordingly (and consistent with the Commission’s previous recommendation in its urban water inquiry), the Council of Australian Governments should, as soon as practicable, commission a review of all forms of assistance for utility services provided across all levels of government. That should include an assessment of whether the Australian Government tax and transfer system could deliver aspects of that support more equitably and efficiently. Based on the outcomes of this review, criteria for assistance for vulnerable consumers, and the means of funding that assistance, should then be written into the NEM-wide network licence conditions.

Delivery of electricity sector specific assistance would of course continue to be the responsibility of parties ‘downstream’ from network operators. However, inclusion of criteria in the licensing conditions would eliminate, or greatly reduce, the scope for jurisdictional governments to compromise the benefits of time basing pricing by pursuing equity or other social objectives through inefficient pricing impositions on network businesses.

DRAFT RECOMMENDATION 11.6

The implementation of cost-reflective, time-based pricing for distribution network services should be accompanied by assistance for vulnerable consumers, which should target those who:

- ***are potentially exposed to large price increases and who do not have reasonable opportunities to switch their demand to non-peak periods***
- ***will potentially face significant difficulty in meeting the charges used to recover the costs of smart meters.***

The Standing Council on Energy and Resources should develop common criteria for identifying who should receive such assistance, and when it should be delivered through electricity specific mechanisms rather than through the Australian Government's tax and transfer system. These criteria should be based on the outcomes of a review commissioned by the Council of Australian Governments of concessions for utility services across all levels of government (consistent with recommendation 8.1 of the Productivity Commission's Urban Water Sector Inquiry report).

These criteria, and a commitment to transparent funding of the electricity sector-specific support should then be reflected in the new National Electricity Market-wide licence conditions for network businesses (draft recommendation 11.2).

The nature of the transition to time-based pricing

The generalised use of time-based pricing for distribution network services is a large step and a big change from the past. While many customers will be winners, there will be some losers. There will be adjustment costs for network businesses, retailers, their customers and the AER. And some important complementary initiatives are required. Accordingly, a carefully planned transition is essential, which involves appropriate engagement between the various stakeholders, and should take into account the costs of change.

As outlined above, the Commission is proposing that this transition process be oversighted and driven by the SCER (draft recommendation 11.1). Specifically the SCER would be responsible for setting timeliness for the various steps in that process, monitoring progress and, as necessary, taking action to address delays.

In the Commission's view, a first and relatively easy step would be to extend cost reflective, time-based, pricing of the network to all large industrial and commercial customers. Such customers already have the required metering, with some already subject to prices that signal the much higher costs of meeting peak demand.

But for smaller businesses and households, the transition to time-based pricing is likely to take considerable time. Indeed, the Commission's modelling indicates that, even putting adjustment costs to one side, a 'big bang' approach would most probably fail a cost-benefit test (chapter 9).

In considering what is required for an orderly and effective transition, it is worth reiterating the desired end point. Time based prices for distribution network services would most probably target around 40 to 80 critical peak hours a year, with retailers reflecting these prices in their tariff offerings to final customers. As discussed

earlier, as well as requiring carefully coordinated roll outs of smart meters, this sort of pricing regime would also necessitate a number of other complementary changes. That includes cost-effective means to signal critical peak prices to customers in advance; the removal of retail price regulation; and appropriate incentive regulations so that distribution businesses are not financially penalised for engaging in demand management. It would also require effective engagement by distributors and retailers with customers (see below). And while the Commission is confident that retailers will pass on time-based prices for network services to many final customers (and provide complementary demand management services and technologies), this should not be assumed.

Another key component of the transition process will be to determine an appropriate path to move from current pricing structures for households and small businesses to the sort of pricing endpoint spelt out above. Obviously, this path will be influenced by actions in other areas — including the roll out process for smart meters (where the lessons learned from Victoria are instructive (chapter 10)); as well as by the outcomes of the tariff trialling process. Accordingly, the Commission has not sought to prescribe particular price paths.

However it observes that wider use of TOU network tariffs embodying relatively broad peak (and shoulder) components might be beneficial as an initial step. While Ausgrid's experiences in NSW indicate that such charges do not achieve significant network efficiencies or offer much prospect of lowering consumer bills overall, they could nonetheless help to:

- increase consumer acceptance of time-based pricing. A survey of Energy Australia customers on TOU tariffs found that 71 per cent believed it was a fairer pricing system (this reflects that TOU tariffs reduce cross-subsidisation between consumers, even if not significantly changing consumption habits).
- provide some useful information and data on the demand responsiveness of customers to time-based differences in prices.

That said, such benefits would not provide a basis for retaining these sorts of pricing regimes for any longer than an interim period. As noted, they are unlikely to be effective in moderating peak demand. (In a cost-benefit analysis of various options to reduce peak demand costs, Deloitte (for ESAA, sub. 23) found that TOU prices had the lowest benefits of any measure — and only one sixth of the benefits of critical peak pricing.) Moreover, an extended period of use would see expensive smart meter technology effectively lying idle. Indeed, the Commission's modelling suggests that if the transition to more robust forms of time-based pricing is too slow, the case for rolling out smart meters in the medium term becomes commensurately more problematic.

With these sorts of considerations in mind, the Commission is seeking more information on appropriate transitional price paths.

The Commission seeks further input from participants on the types of price paths that might be appropriate in transitioning to cost-reflective, time-based network pricing, including on:

- *any impediments to the early extension of such pricing to all large commercial and industrial users*
- *the benefits and costs (including that of a smart meter) from initially extending the use of ‘time-of-use’ network prices — employing peak, shoulder and non-peak tariffs — to all households and small businesses*
- *any ways that such prices could be usefully and quickly improved to be more targeted — such as through seasonal loadings — to reflect the costs of providing network services at peak times*
- *how quickly it would be appropriate to introduce greater geographic differentiation in network prices*
- *what indicators should be used to review how well the price transition process is progressing.*

It is also seeking further input on how the nature and speed of the transitional price path might be influenced by the costs and benefits of technologies (other than the smart meter itself) to improve responsiveness to price signals and assist with informed energy use decisions, including:

- *‘smart appliances’ that are enabled with a demand response capability (chapter 10) (such as to allow direct load control with a customer’s agreement)*
- *‘add-on’ technologies, such as Home Area Networks, in-home displays, online portals and phone Apps, that draw on information provided by a smart meter to assist with a consumer’s energy management*
- *information technology systems to communicate to customers, such as to provide notification of critical peak events.*

The importance of effective engagement and customer education

Whatever the particular transition path adopted, it is critical that there is appropriate consultation and information exchange between the various stakeholders. As outlined earlier, distribution network businesses, retailers, the AER, state and territory governments and customers (or their representatives) will all need to be satisfied that the reforms are progressed appropriately.

One of the tasks of the SCER in its role of overseeing the implementation process (see draft recommendation 11.1) would be to ensure that, in a broad sense, there has been adequate engagement between the parties. A further focus, and one that is already an objective within the SCER's *Demand Side Participation Work Plan*, would be to ensure customers can easily assess the costs and benefits of electricity consumption decisions and access information about options to change their consumption. Within this framework, the SCER could add forward priorities to the objectives of 'informing choice' and 'enabling demand response'. Consequent actions and decisions should be informed by evidence from robust pricing and technology trials, and based on a cost-benefit framework.

However, in the Commission's view, there would be benefits from imposing a formal requirement on distribution network businesses to engage with retailers very early in the development phase of revising network price structures. Specifically, it would help to:

- reduce the possibility that the costs of meeting peak network demand continued to be hidden (or excessively smoothed out) in the retail price face by consumers
- increase the confidence of retailers entering the market and encourage the development of more innovative retail tariff offers (chapter 12)
- assist distribution businesses to understand the potential problems that changes to network tariffs could impose on retailers (box 11.6).

Similarly, a formal requirement for distribution businesses and retailers to engage with consumers is warranted to ensure that consumers are well placed to respond appropriately to time-based pricing; are aware of the implications for their electricity bills; and are aware of the support mechanisms in the event that the new pricing regime will create financial difficulties for them. More specifically, such engagement and education should encompass the timing and cost of smart meter installation; the basis for the different components of time-based prices; the timetable for steps in the transition to the new pricing regime; the way in which consumers will be advised of critical peak pricing events; and the various options available to consumers to better manage their demand.

Box 11.6 Ameliorating the transitional costs for retailers

Retailers already have to deal with different network tariffs applying across customer classes and the service areas of distribution businesses. However, with cost reflective, time-based, pricing, the complexity of the price formulation process would increase and with it the administrative costs of appropriately reflecting those prices in retail tariffs. (As raised in chapter 10, the operation of a centralised smart meter data management system could help to lessen, though not eliminate, this additional administrative burden for retailers.)

With the introduction of time-based network prices, retailers would also have to reassess their hedging strategy (smoothing of price volatility in the wholesale energy market) and communicate tariff changes to their customers. Advanced notice of network pricing changes is helpful.

An existing instrument to inform retailers and customers about forthcoming distribution prices is a statement of expected price trends, which distributors are required to update for each regulatory year (cl. 6.18.9(3) of the Rules). But prior to an actual change in network tariffs, retailers only need be given 20 business days' notice. In the absence of earlier engagement, such short notice could make a smooth transition to time-based pricing difficult for retailers. Indeed, the sort of engagement catered for by this rule is seemingly of a much more minor kind than the sort required for major pricing reforms.

DRAFT RECOMMENDATION 11.7***The Australian Energy Regulator should require:***

- *distribution network businesses to demonstrate that they have actively engaged with retailers very early in the development of new time-based pricing structures, including on ways to incorporate those charges in retail prices to clearly signal to customers the costs of meeting peak network demand*
- *distributors and retailers to demonstrate that they have engaged with, and educated, customers prior to the introduction of smart meters, and again prior to the introduction of new time-based customer tariffs.*
 - *Such engagement should occur sufficiently early to ensure that customers have the knowledge and time to respond appropriately to time-based pricing (including of the various means to manage their peak demand); are aware of the implications for their electricity bills; understand the way in which advance warning of critical peak pricing events will be communicated; and are aware of the support mechanisms in the event that the new pricing regime creates financial difficulties for them.*

12 Complementary reforms to support demand management

Key points

- Locking in the benefits from time-based network charges calls for complementary reforms to the incentive regulation of network businesses and retail price regulations.
- Price and revenue caps link the revenue that can be recovered from network services to the amount of annual revenue approved under the AER's building block determination.
 - Different caps, or combinations of caps, are applied to different distribution businesses, while all transmission businesses face a revenue cap.
 - Substantial changes to transmission pricing are not envisaged for some time, which leaves no immediate cause to change from a revenue cap for transmission services.
 - Isolating the incentive effects of either revenue caps or weighted average price caps (WAPC) for distribution businesses is complex, but the impact on incentives to set distribution network tariffs efficiently is important
 - While revenue caps provide stronger incentives for (non-price) demand management, alternative instruments can correct for the disincentive under WAPC.
 - Compared to revenue caps, weighted average price caps appear more consistent with distribution businesses having incentives to price efficiently.
- The potential inconsistency of retail price regulation with the long-term interests of consumers has been acknowledged by all governments in the NEM, as recognised by the 2006 COAG agreement supporting a process for their removal in electricity.
 - However, retail price regulations remain in all jurisdictions excluding Victoria.
- The success of the phased and coordinated suite of reforms proposed in chapters 10 and 11 rests squarely on pricing flexibility, competition and innovation in the retail sector. Therefore, although the removal of retail price regulation has been advocated widely, there is potentially much more at stake this time around.
 - The removal of retail price regulation is necessary to allow a vibrant and competitive retail market to develop. Further, since cross-subsidies between consumers would continue to be embedded in regulated prices, the removal of these regulations is needed to encourage retailers to pass-on more cost-reflective network charges to end-users.
 - There would be little point proceeding with the necessary reforms unless retail price regulations are removed (or a process engaged for their phased removal).
 - To support favourable outcomes for consumers choosing between retail offers, the removal of price regulation should be accompanied by access to more independent information to help support consumers make good choices. To support this, the AER could expand its existing online comparison tools.

The importance of smart meter technology as a prerequisite to cost-reflective pricing and more efficient adoption of other forms of demand management was discussed in chapter 10. Chapter 11 establishes the changes necessary to achieve a gradual progression to time-based network charges that reflect the additional costs of providing peak capacity.

This chapter looks at two complementary areas for reform:

- the incentives of network businesses under the current regulatory regime to set efficient prices and engage in demand management strategies (section 12.1) and
- market imperfections in the retail sector (section 12.2).

Addressing each is necessary to realise the benefits of cost-reflective network pricing and wider uptake of demand management.

12.1 Incentive regulation of network businesses

A key goal of adopting efficient network pricing is to control inefficient growth in investment in peak-specific distribution infrastructure. The incentive regulation framework should support this objective, but aspects of the current framework could reduce the incentive for network businesses to set efficient prices and engage in other demand management strategies (such as load management schemes).

These aspects of incentive regulation are addressed in this section. Given this purpose, the section does not seek to comprehensively assess the current regulatory regime of network businesses — chapter 5 discusses the incentive regulation framework broadly and, following specific reforms, its compatibility with benchmarking. Rather, the focus here is on ensuring that distribution businesses have the capacity and, where possible, appropriate incentives to implement efficient pricing. Regulatory arrangements to support non-price forms of demand management are also assessed in this chapter, with a view to ensuring the regime supports such options without weakening incentives for cost-reflective pricing.

Revenue control mechanisms and cost-reflective pricing

Revenue control mechanisms, such as price and revenue caps, provide a link between what network businesses can charge for services and the ‘maximum allowable revenue’ (as calculated using the building block methodology (chapter 5)). They are an important tool in incentive regulation and have the potential to affect network business’ behaviour in managing risks, minimising costs, pricing efficiently and undertaking other forms of demand management.

The two main forms of control mechanisms are a revenue cap and a weighted average price cap (WAPC).¹ A key difference between these caps is how various uncertainties affecting revenue recovery (such as from demand shocks or errors in forecasts) are adjusted for (if taken into account at all). As currently applied by the AER:

- revenue caps explicitly incorporate ex-post adjustments to revenues if the demand is not as forecast, to ensure that the business actually recovers the specified revenue cap — no more and no less²
- under the price cap model, once ex-ante demand forecasts and weighted average prices are approved by the AER, no subsequent adjustment is made for errors in forecasts.

This section discusses the relative merits of different control mechanisms for distribution businesses. A key issue is to what extent a revenue cap or a WAPC provides the best incentive to set prices efficiently. The appropriateness of a revenue cap applying to transmission businesses is not evaluated. In the Commission's view, given the differing characteristics of transmission assets, and the revenue implications of the proposed introduction of optional firm access (chapter 18), substantial changes to transmission revenue control mechanisms are not warranted at this time. Transmission businesses should continue to operate with revenue caps.

For distribution businesses, in the Commission's assessment, a WAPC is more likely to facilitate adherence to efficient pricing principles than a revenue cap.³ The compatibility of a WAPC with efficient pricing incentives aligns with the AEMC's assessment. In their view, a WAPC provides distribution businesses with a stronger motivation, than is provided by revenue caps, to price efficiently (at levels that reflect actual costs, especially at peak demand times on their networks):

... as a means to ensure that revenue recovered is sufficient to cover costs and therefore will set tariffs that discourage consumption at peak (where meeting that extra consumption will result in the network business incurring a loss). (AEMC 2012b, p. 20)

¹ The Rules allow the AER to choose a control mechanism to apply to each distribution business. Currently, distribution businesses in NSW, Victoria and South Australia are subject to a weighted average price cap, while Queensland and Tasmania are subject to revenue caps, and the ACT to a maximum average revenue cap (which is similar to a WAPC). All transmission businesses are subject to revenue caps.

² In practice, where time-based pricing is not adopted, the application of 'side constraints' — restrictions on year-to-year price increases within a regulatory cycle (cl. 6.18.6) — may interfere with the intent of recovering exactly the approved revenues over a regulatory cycle.

³ While revenue caps could be modified to provide incentives similar to a WAPC, they are likely to be more complex to set up and regulate. Moreover, under such approaches, price signals to customers are likely to be less directly linked to each consumers' contribution to network costs (as year-to-year adjustments would be lagged, prices in the subsequent year would be either higher or lower than the efficient level, which will distort consumption decisions).

The AER similarly recognises the incentives for efficient pricing provided by a WAPC, but cautions that the expected benefit in distribution network service providers' pricing has not been observed in practice (2012a, p. 47).⁴ However, the Commission notes that the apparent lack of evidence to support that a WAPC provides stronger incentives to price efficiently than revenue caps may be explained by several factors including:

- that smart meters are required to implement efficient pricing, and until there is a sufficient penetration (and utilisation) of smart meters, there will be little practical benefit from a WAPC
- directives from government to pursue equity objectives may derail a distributors' desire to price efficiently. (box 12.1)

With the gradual rollout of smart meters, scope for the adoption and effectiveness of efficient pricing will be improved. Further, to allow a WAPC to support cost-reflective pricing, regulatory changes of the kind outlined in chapter 11 would continue to be necessary. Nevertheless, in the Commission's view, although a WAPC provides a stronger incentive to distribution businesses to price their network efficiently than does a revenue cap, that incentive may not be sufficiently large on its own. This again reinforces the need for other reforms to facilitate efficient network pricing.

The relevance of other criteria

In the Commission's view, the main purpose of the control mechanism should be to support (and certainly not detract from) efficient pricing. While a WAPC is most appropriate to support that goal, there is the contention that it:

- does not sufficiently constrain the potential for distribution businesses to recover revenues in excess of the approved annual allowance
- does not provide efficient incentives for non-price based demand management.

The relevance of these concerns, including whether they could be addressed more appropriately through other means, is discussed below.

⁴ In the absence of smart meters (which can allow time of use and critical peak pricing), it is not clear what the AER would consider as evidence of efficient pricing.

Over-recovery of revenue

Distribution businesses subject to a WAPC and with a capacity to apply time-based network charges may over- or under-recover approved revenue for a range of reasons, including:

- because of variability in the prevailing weather conditions resulting in unforeseen fluctuations in demand for peak capacity
 - This is efficient on the basis that revenues are more closely linked to the consumption that imposes the greatest system-wide costs and necessitates investment
- because some customers, even when facing cost-reflective prices at times of peak demand, may make a choice to pay a high price and continue to use more power than forecast at peak times
 - This is efficient provided that the prices paid genuinely reflect the costs of providing the additional network capacity at peak times (allowing the network company to invest more capital to provide the additional network capacity to meet this demand requirement).
- through unforeseen growth in demand that is unresponsive to prices applying in non-peak periods
 - This could (in part) be inefficient to the extent that the higher than forecast demand is linked to price discrimination by the network business — the practice of deliberately differentiating customers and charging higher prices to those that are unresponsive to prices than to others who are price sensitive.
 - In practice, the Commission considers that there is limited scope for distribution networks to deliberately raise revenue by price discrimination under WAPC⁵. Nevertheless, the AER would have an opportunity to address any such concerns directly in the process of approving distributors' pricing proposals.
- due to 'errors' in forecasts of demand that determine the WAPC. Such errors will be inevitable given variability in weather patterns over time and associated fluctuations in peak demand. However, provided the AER takes into account alternative forecasts provided by independent agencies like AEMO and benchmark forecasts against the experience of other DSPs over time, forecasting errors should reduce.

⁵ To the extent that profits do rise, however, this may be considered 'the price' of businesses having incentives to efficiently price peak consumption and also bear the risk of year-to-year variability in revenues (return on peak investments) (Ausgrid 2012a).

Accordingly, in the Commission's view, the building blocks revenue determination, combined with a closer commitment to efficient pricing principles, should be the key means by which distribution businesses are bound to recover efficient costs. Further, the AER should ensure that demand forecasts are not systematically biased.

Incentives for demand management

With network prices that reflect the long-run costs of meeting peak demand, the main focus of (non-price) demand management is to achieve cost-effective short term deferral of network augmentation projects.⁶ Such demand management can take various forms including peak load management schemes, with participation of end-users facilitated through 'side-payments' to end-users (mostly commercial and industrial customers).

At the start of a regulatory period, businesses may not know the number of demand management projects they will undertake and what reduction in peak load will be achieved. As such, the WAPC is likely to be set based on demand forecasts that do not take account of the full potential for peak load reduction. Therefore, the demand management activities of distribution business may cause them to under-recover their approved revenue.

Recognising this, the AER administers a scheme — the Demand Management and Embedded Generation Connection Scheme — 'part B' of which compensates distribution businesses under WAPC for any revenue they forego from undertaking cost-effective non-tariff based demand management. The situation is automatically addressed for businesses under a revenue cap, as demand volumes are 'decoupled' from revenues through an 'unders' and 'overs' account that adjusts the revenue allowance from year-to-year.

⁶ The 'payoff' for network businesses to undertake non-price demand management projects (under either a price or revenue cap) would be the short-term value of deferring a planned network investment (less the costs of achieving the required reduction in peak consumption). Direct load control of household appliances (as proposed in chapter 10) could be a candidate to allow the short-term deferral of network investments. Where smart meters are available to implement efficient pricing, network prices (that signal the LRMC of providing peak capacity) would provide end-users with an incentive to participate in such programs. However, an additional 'side-payment' could be offered to consumers accepting direct load control, which would signal the value of deferring a lumpy network investment. Similarly, industrial and commercial sources of load reduction could be offered 'side payments' if they could provide a cost effective means of delaying the timing of a lumpy network investment.

Box 12.1 Some divergent thoughts on control measures

The AER is currently evaluating the choice of control mechanism for NSW and ACT distribution determination 2014-19. They have indicated a (preliminary) preference for revenue caps, indicating that a revenue cap is more effective at limiting over-recovery of revenues, which in their view outweighs the drawback of weak efficient pricing incentives (2012a, p. 47).

In reaching this preliminary position, the AER acknowledged that a weighted average price cap (WAPC) creates some scope for beneficial rebalancing⁷ of tariffs by distribution businesses, and is favourable for efficient pricing. However, having observed little evidence of efficient price structures in practice and concerns about distribution businesses raising substantial additional revenue under WAPC:

The AER considers that during the regulatory control period DNSPs were able to make windfall gains by increasing the price (above the general increase specified [by CPI-X] in the WAPC) of components of particular services experiencing sales growth above its forecast. (AER 2012a, p. 128)

The Commission notes that the regulatory period under consideration by the AER (2006–10) coincided with a sequence of hotter than average years, as was evidenced by the rate of growth in peak demand over that period (even in states where WAPC were not in use). As such, it is unclear what role (if any) WAPC had in causing or permitting such increased consumption, and whether that should be a concern given:

- extra revenue would be consistent with a potential increase in the underlying costs of distribution businesses, given that peak investment costs increase substantially with growth in peak consumption
- even if price discrimination (targeting consumption that is less responsive to prices) did provide opportunities for businesses to make additional revenue, it would only translate into profits where the additional consumption (above forecasts) occurs in non-peak periods.

Give the objectives of the DMEGCIS, network businesses should have incentives to pursue non-price demand management programs that are broadly equivalent under either form of cap. A complicating factor is that, as discussed below, there is some contention about the effectiveness of the scheme — now called the Demand Management and Embedded Generation Connection Incentive Scheme (DMEGCIS).

The Commission considers that directly addressing any problems associated with the current operation of DMEGCIS operating with WAPC would be preferable to foregoing opportunities for more efficient pricing by choosing revenue caps as the control measure. Non-price demand management is also an important part of the

⁷ Rebalancing is a broad term used to describe the removal of cross-subsidies in tariffs or making tariffs more cost-reflective. That can include rebalancing between residential and other users, rebalancing between peak and non-peak periods, or rebalancing between fixed and variable charges.

broader objective of achieving network efficiencies. Accordingly, the DMEGCIS should be reviewed by the AER to ensure it operates effectively to support deferral of lumpy network expansion projects (on the same basis that efficient network pricing would support demand management on a permanent basis).

In summary

In the Commission's assessment, a WAPC appears to be the preferable means of providing incentives for efficient network pricing, particularly in periods when consumers' electricity usage imposes the greatest system-wide costs (which in turn should encourage customers to change their usage patterns). It would be difficult to implement cost-reflective pricing as efficiently using revenue caps.

Incentive schemes for demand management

The DMEGCIS consists of two parts:

- part A — the Demand Management Innovation Allowance
- part B — the recovery of forgone revenue.

The scheme aims to assist distribution businesses to implement non-network alternatives, to manage the expected demand for distribution services in some other way, or to connect embedded generators. It is not meant to be the primary source of recovery for demand management expenditure. Rather, it is meant to act as an additional incentive where the initiative has not been included in the core revenue proposal when the distribution determination was made, or to correct disincentives inherent in the regulatory framework (such as under part B of the scheme directed at distribution businesses under WAPC) (AER 2012a).

The demand management incentive scheme has been criticised on a number of fronts. One is its limited use by distribution businesses. Another is that the forgone revenue component (part B) of the scheme fails to mitigate the disincentive to undertake demand management. EnerNOC, for example, said that while the scheme is intended to reimburse distribution businesses under WAPC to neutralise the disincentive:

... this is an awkward, inefficient approach, as each demand management project requires separate approval by the AER. As well as causing bureaucratic overhead, this leads to [Network Service Providers] perceiving a risk that they will not be reimbursed. (sub. 7, p. 2)

That compensation is contingent on a demand management project being 'cost-effective' adds an extra hurdle for distribution businesses, but at first inspection, it

would appear to be a desirable feature of the scheme. Even so, it is an additional regulatory burden on network businesses operating under a WAPC (and the AER) that they would not face under a revenue cap.⁸ In the Commission's view, the assessment of the cost-effectiveness of a demand management project should not be interpreted so strictly that it deters a distribution business from undertaking or even exploring potential demand management options. Nor should the scheme be overly burdensome to administer — the AER claims that the current scheme is costly to implement (AEMC 2012a).

Recognising the potential for shortcomings in the scheme's operation, the AEMC has made an interim recommendation that it be reviewed by the AER. The Commission strongly supports the AER investigating scope to improve the DMEGCIS, given its critical role in ensuring that distribution businesses that are subject to a WAPC retain incentives for demand management.

The value of information and innovation

The AER will require more detailed information to perform many of the new functions recommended by the Commission in the area of demand management. Information will be required to:

- accurately assess the costs and benefits of smart meters (draft recommendation 10.1)
- perform the functions suggested in draft recommendations 11.4 and 11.5. These include approving reasonable forward-looking forecasts of peak demand and estimates of the long run marginal cost (LRMC) of peak capacity, and modelling the demand responsiveness of end-users to cost-reflective pricing.

To help obtain the right information (and to encourage network businesses to develop expertise in demand management), the Commission considers that the AER should increase the innovation allowance component of the DMEGCIS.

Approval of innovation funds should cover pricing trials and other (peak) demand management experiments that meet relevant criteria. Conditions on the funds made available should recognise the beneficial impact of 'spillovers' from such research and trials and require the availability of trial data for wider public analysis. As such:

- pre-approval of funds should be required, which should ensure robust experimental design and consistent observation of variables, including characteristics of end-users. Where appropriate, progress payments should also

⁸ Since, under a revenue cap, the difference between actual and forecast volumes are automatically adjusted for in subsequent years.

be used, especially for larger projects. There should be a capacity to provide payments to retailers involved in the trials, as their participation and cooperation will be critical to the success and the learning from the trials

- final payment would require that all data be provided to the AER, which should then be ‘de-confidentialised’ data and made available to third parties for analysis, including academic institutions
- the data should be analysed to yield estimates of price responsiveness, assist with tariff design and inform the AER in undertaking cost-benefit analysis of smart meters (draft recommendation 10.1).

Valuing the net-benefits of demand management

Non-network alternatives (distributed generation and demand management) may yield benefits in deferred investment that extend beyond a single determination period. Currently, when a network business chooses not to spend the approved capital allowance for a network augmentation and instead adopts a demand management solution, it is rewarded only until the end of the 5-year regulatory period. It is argued that this stymies some demand management possibilities that would deliver benefits beyond the regulatory period.

The exception is when network businesses seek ex-ante approval of expenditure for longer-term demand management projects from the AER (during the regulatory determination phase). The one case of which the Commission is aware is the AER’s approval of expenditure for Energex and Ergon to undertake demand management projects over the current 5-year regulatory period. Energex was approved \$107 million in expenditure to permanently defer (avoid) investment in 144MW of network capacity (compared to the ‘business as usual’ load growth scenario).

In addition to the timeframe over which benefits are valued, some participants told the Commission that it is unclear that the market-wide net benefits (or net benefits to consumers) from demand management projects are valued within the current framework.

With the full implementation of the package of reforms proposed by the Commission, it is intended that all impediments that network businesses currently face in procuring funding for demand management projects would be negated. In particular:

- network businesses can defer network capital investments over the shorter term (within a regulatory cycle), depending on the annual deferral value of the capital (less expenses to implement the demand management solution). Chapter 5 has

proposed changes to the incentive regulation framework that should ensure network businesses have incentives to reduce inefficient capital expenditure and have balanced incentives between operating and capital expenditures.

- over the longer term, cost-reflective network pricing (based on LRMC of providing peak capacity) is the appropriate demand management tool of distribution businesses (draft recommendation 11.3)
- the Commission has proposed a process for the roll-out of smart meters that sits outside of the normal regulatory determination process (draft recommendation 10.1)
- the case of Energex and Ergon suggests that network businesses already appear to have a capacity to obtain ex-ante approval of demand management funds (including for demand management assets delivering longer term benefits).

If the full implementation of the Commission's package of reforms were to significantly fall behind schedule, additional measures may be appropriate. If there was evidence that opportunities for efficient demand management were being forgone by network businesses because of conflicting or weak incentives, the AER should investigate scope to provide network businesses with additional (efficient) penalties or incentives as appropriate to overcome this problem.

It is a separate issue whether businesses should explicitly be *rewarded* (paid above their costs) for implementing demand management projects that deliver net benefits to consumers — projects that provide a long-term market-wide benefit. Distribution businesses suggest that they lack efficient incentives because they do not earn a *share* of the market-wide net benefits. However, the practical difficulties and potential risks and uncertainties of valuing and allowing distribution businesses to share in the market-wide benefits from demand management approaches are significant. That is, in part, why the Commission did not recommend such an approach for funding smart meter rollouts, which is both a long-lived demand management asset and gives rise to market-wide benefits. Nevertheless, there may be grounds for the AER to investigate the appropriateness of any such payments to network businesses.

The influence of the WACC

As discussed in chapter 5, the WACC may bias network business's spending decisions away from 'opex' to 'capex', reducing the incentives for businesses to use pricing or other demand management methods to reduce such spending. Chapter 5 discusses options in this area. These matters are also being considered in the limited merits review and the rule change proposals put to the AEMC by the AER.

Other changes proposed by the AEMC's *Power of Choice* review

Addressing the incentives of network businesses (and all market participants) to adopt demand management is a focus of the AEMC's *Power of Choice* review. The AEMC gives particular focus to securing demand-side participation from commercial and industrial end-users, where there is likely to be a high prospect of 'low hanging fruit'.

The Commission has sought to avoid duplicating much of this review, including the AEMC's proposal to allow reductions in load to be offered by demand aggregators to the NEM spot market. The Commission has not analysed the finer details of this proposal, but observes that:

- in principle, the AEMC's proposal appears beneficial, pending the identification of any unintended consequences during the consultation process
- demand aggregators may be able to source load reduction more cheaply than retailers, and could also provide a link between the underlying market value of distributed generation sources and spot market outcomes
- removing barriers to demand aggregators participating in the spot market could allow more cost-effective load curtailment to address network congestion. (Given largely fixed negotiation and contracting costs, there are efficiencies in aggregating demand response for both network and wholesale purposes.).

DRAFT RECOMMENDATION 12.1

Coinciding with the gradual roll-out of smart meters to allow more cost-reflective network pricing, revenues from all distribution network 'standard control services' should be subject to regulated weighted average price (not revenue) caps. This should not apply to transmission businesses, which, given the complexities and lower net-benefits, should continue to be subject to revenue caps.

DRAFT RECOMMENDATION 12.2

The Australian Energy Regulator should review the operation of, and the incentives provided by, the Demand Management and Embedded Generation Connection Incentive Scheme. In doing so, the Australian Energy Regulator should ensure that distribution companies' incentives are appropriately aligned with the objective of achieving efficient demand management. The innovation allowance component of this scheme should also be increased.

Given the package of draft recommendations in this report, the Commission seeks feedback on what (if any) barriers remain in the National Electricity Rules (or the Australian Energy Regulator's application of the Rules) that could impede an efficient level of demand management.

12.2 Retailers' incentives and price regulation

Currently, retailers compete mainly on the price packages they offer to end-users, the efficiency of their billing approaches, and on the effectiveness of their marketing to attract new customers. To allow them to present an attractive package to customers, they have to be able to exercise tight control over their costs through activities such as:

- their capacity for efficient hedging,
- their ability to contract with generators (in some cases, through common ownership between retailers and generators to provide a natural hedge)
- their access to competitive finance to efficiently fund their working capital.

Industrial customers aside, retailers have little capacity or incentive to create new products for customers that would prefer lower electricity prices in exchange for reduced demand at peak times. This reflects that:

- retail price regulation in the residential market (and, in some jurisdictions, the small-medium business market) preserves the cross-subsidies from non-peaky customers to peaky consumers. This reduces the price advantages for consumers that are willing to curtail their peak demand use
- smart meters are not available to offer more innovative tariff packages, including demand management services.

The result is restricted choice for consumers.

Chapter 10 outlined a process for the gradual rollout of smart meters and chapter 11 outlined ways in which benefits could be delivered from that investment through the implementation of appropriately structured network charges. The benefits from each of those changes (and indeed the argument to implement these changes) would be jeopardised by a retail sector that lacked sufficient competition. Likewise, the benefits would be reduced if retail business were slow to adjust to a new market model (one in which consumers could be provided much wider choice in tariff offers and demand management services). Accordingly, to support the Commission's package of reforms, an important preparatory reform is required — the removal of all retail price controls and the removal of compulsory default retail

schemes that effectively place a cap on prices offered in the jurisdiction. The case for this reform is discussed immediately below, and the remainder of the chapter then assesses how the behaviour of retailers would be expected to change.

Retail price regulation

Retail price regulation was introduced into the electricity (and telecommunications) markets with the deregulation of integrated monopoly services, as a transitional consumer protection measure until competition developed. It was to be subject to review and removal once full retail contestability had been established.

The merit of price regulation as an *interim* tool is not debated. However, once contestability between retailers is achieved, retail price regulations have little role to play, with competition among suppliers serving consumers' interests most appropriately and keeping prices in check over the longer term.

Retail price regulation should not be used to address affordability issues, including by keeping prices artificially low. Doing so, even for short periods, can deter the entry of new retailers, cause the exit of existing retailers, and thus reduce potential competition, which ultimately leads to inferior outcomes for consumers in the longer term.

Accordingly, the Commission along with many others has previously advocated the removal of retail price regulation in the electricity market, recognising its potential inconsistency with the long-term interests of consumers (PC 2008; PC 2012b; DRET 2011). To date, only Victoria has removed retail price regulation in the electricity sector, despite a process for their removal having been agreed by COAG since 2006 (subject to assessment of contestability by the AEMC).

State regulators under delegation from the relevant Minister set regulated retail prices. The regulated 'standing offer' or a 'notified' price is then required to be available to residential and some smaller business consumers.⁹ Consumers can choose to purchase (unregulated) market offers, although these are effectively

⁹ The prices set are intended to ensure an electricity retailer can recover costs that an 'efficient' retailer would expect to incur. Each electricity retailer must submit an application to the state regulator outlining its expected costs for the period ahead. The retailer is also provided with a 'reasonable' margin (on top of retail operation, energy, network costs), which ranges from 3-10 per cent depending on the jurisdiction (RBA 2010). The phasing out of retail price regulations has usually commenced with the removal of price regulation for large business customers, followed by small to medium business customers (a change recently signalled to occur in NSW (Macdnald-Smith 26-Sept. 2012, p. 12 AFR)), and residential customers usually the last customer segment reviewed.

‘capped’ by the standing offer, with market offers typically taking the form of a percentage reduction from the benchmark of the standing offer.

The emergence of competition is also affected by the amount of ‘headroom’ between the standing offer price and a retailer’s actual supply costs, since that margin provides the incentive for entry of new retailers. If there is no headroom, or worse still the regulated standing offer price is held below costs, the likelihood of a vibrant retail market is significantly reduced. Incumbent retailers would also start to exit the market.

The dependency between the regulated and unregulated product is reinforced by some consumers’ perceptions that a control on prices signals a ‘good deal’, discouraging them from ‘switching’ to a potentially cheaper market offer. (A lack of switching or customer inertia can further stifle competitive outcomes and frustrate the achievement of lower prices.)

However, there is evidence that consumers can do significantly better under most market rates offered by competing retailers than remaining on a regulated product and, as indicated in figure 12.1, usually to the tune of several hundred dollars a year. (This does not apply in Tasmania, where there is only one retailer, and there is little evidence of cheaper deals in the ACT given the incumbent’s dominant market position.) Also of concern is that some analysis has found a disproportionately large share of consumers on the more costly regulated retail product are on low incomes (ESCOSA 2006).

In Queensland, the standing offer has removed significant ‘headroom’ following the introduction of the 12-month tariff freeze in July 2012. As such, market offers would now generally be above the regulated rate and the removal of retail price regulation would likely see prices increase in the short term. While this measure to artificially hold down prices was motivated to lower the cost of living, in the longer term, such a measure will not best serve consumers’ interests. Rather than through retail price regulation, the underlying cost pressures that are causing prices to increase need to be addressed, including by the suite of measures proposed in this report.

Because retail price regulations hinder the development of a competitive retail market, prices may initially rise when they are removed if incumbent retailers take advantage of their market power to increase profits. However, any increase in profits would quickly attract new entrants to the market and increase competition, resulting in lower prices over the longer term. Nevertheless, governments may prefer to adopt a more gradual approach to remove price regulation in jurisdictions where regulated price settings have prevented a competitive retail market

developing. That could include the phasing out of price regulations by making them progressively less ‘binding’ over time, but with a view to withdraw their influence on the market permanently once competitive outcomes are more certain. During any such process, it would be important to raise consumer awareness about the ability to get a ‘better deal’ from purchasing electricity services from the market. (However, any such communication should not be presented as a guarantee, since there may be some less scrupulous retailers — as is the case in any competitive market.) Consumer awareness and ‘caveat emptor’ remain important considerations as for most products that consumers buy every day.

Governments would clearly be interested in minimising risks for consumers whose inexperience in purchasing their electricity services from a competitive market could result in them signing on to a worse deal. Similarly, it could help to drive competition by shining a light on the relative competitiveness of retail market offers. To that end, there would be benefits in ensuring that consumers have access to an independent source of comparison information when choosing among retail contracts. Already, online sources of comparison information exist, but maintaining the independence and, in turn, consumers’ confidence in such information is crucial. A national online tool would be most effective to brand and market to consumers, which could build on the existing ‘energy made easy’ online comparison site established and maintained by the AER (as part of its new retail responsibilities under the national energy customer framework).

While previous grounds for removing retail price regulation were sound, the fact that most consumers do not have smart meters has significantly limited the scope for more innovative time-based tariff offers to drive competition at the retail level and efficiencies in the network. This suggests that the potential benefits for consumers from the removal of retail price regulation may be even greater in future than when it was initially agreed by COAG.

The success of the phased and coordinated suite of reforms proposed in chapters 10 and 11 rests squarely on pricing flexibility, competition and innovation in the retail sector. There would be little point in proceeding with the necessary reforms unless retail price regulation is removed to:

- help retail competition to develop further, including by attracting the entry of new retailers into regulated market segments
- support innovation.

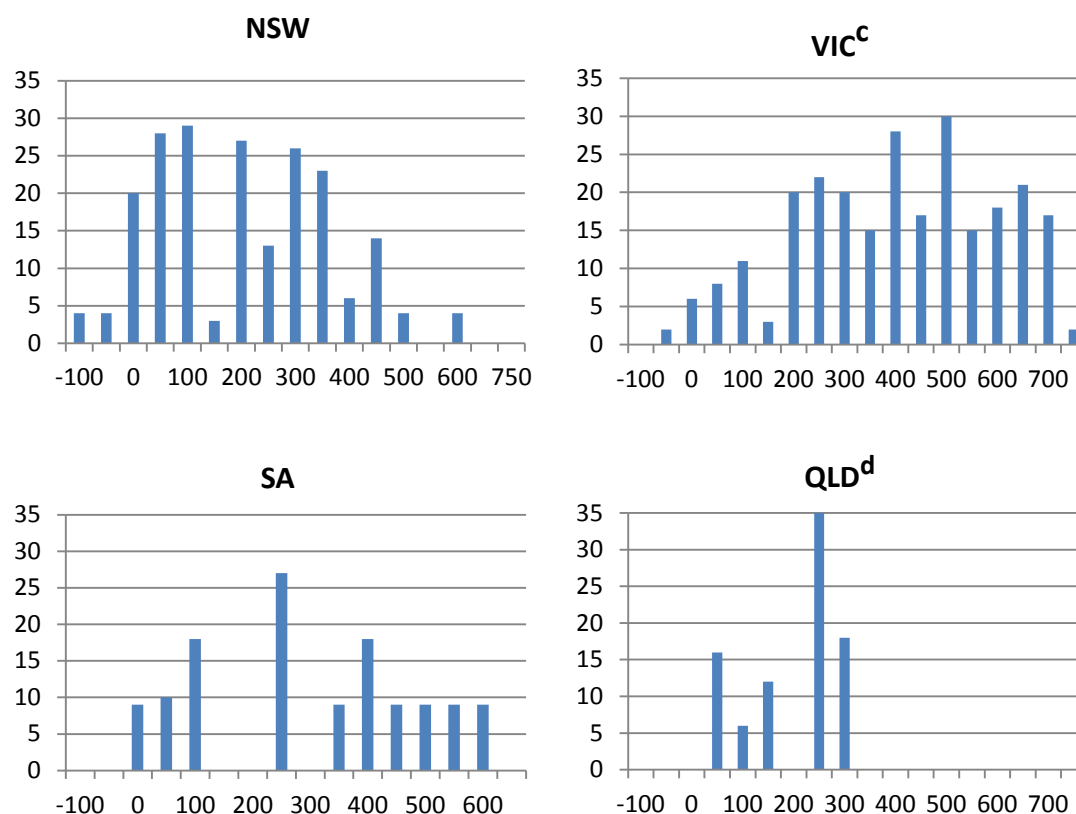
The obstacle created by retail price regulation is that it gets in the way of consumers facing more efficient price signals — a point widely acknowledged by participants:

What is clear is that exposure to efficient prices is likely to be the most significant driver of change to end use electricity demand. However, this is unlikely to happen whilst retail price setting remains largely in the hands of government. (Loy Yang Marketing Management Company, sub. 25, p. 3)

With progression towards efficient time-based pricing of network tariffs, retailers will play a key role in fashioning and re-packaging tariff offers to meet a wide range of consumer preferences and needs. This includes different levels of exposure to peak prices, different levels of price smoothing (in exchange for an appropriate premium) and different billing periods to assist with budgeting.

Figure 12.1 Annual savings from market offers^a

Frequency of offers (vertical-axis) by category of annual dollar savings (horizontal axis) when compared to the standing offer in 2012^b



^a Excludes green energy offers ^b A broad geographical range of postcodes surveyed (n=10); assuming medium range annual consumption of 2100kWh. ^c While Victoria no longer has retail price regulation, standing offer tariffs are still gazetted (under the Electricity Act 2000) to apply in cases where customers have not yet entered into a market contract. ^d Annual price savings may not reflect the current potential for savings, given the recent 'freeze' of regulated retail charges (tariff 11).

Data source: <http://www.switchwise.com.au/>

To assist households in managing their exposure to higher peak prices in the future, and to take advantage of opportunities to make savings by shifting the timing of their electricity use, retailers will need to add value to their existing service range. This will be likely to involve providing:

- electricity demand management services, including assessments of household appliances and bill consultations
- add-on technologies to optimise the use of smart meters, provide real time consumption information, warnings in advance of peak consumption days, warnings about bills exceeding a pre-agreed threshold in a billing cycle, and, where desired by consumers, to facilitate load control services, or automate other aspects of electricity use.

Price regulations applied to a time-based tariff would be extremely complex and costly for state regulators to administer in order to avoid locking-in cross-subsidies for peaky users (box 12.2). This mainly reflects that the authorities determining regulated prices would find it difficult to adjust for the changing average load profile (and associated cost) of supplying the group of customers served by the regulated (load weighted average) price.

In summary, the Commission considers that all state and territory governments in the National Electricity Market should remove all retail price regulation of electricity. The exception would be where the Australian Energy Market Commission advises that there is strong evidence that competitive pressures would be weak after the removal of the regulation and could not be addressed by consumer awareness measures. Proposals to open up the Tasmanian market to competition have recently been put forward by an expert panel and should be progressed by the Tasmanian Government as soon as possible, drawing on advice and input from the AEMC.

A second best option, should governments refuse to remove retail price regulation, would be for governments to agree to phase out retail price regulation according to a strict timetable. That should include implementing consumer awareness measures and any necessary structural reforms suggested by the AEMC to develop workable competition. Such phased removal should be completed by 2015. Regardless of any such timetable, retail price regulation should not apply in network regions where smart meters have been (or would soon be) rolled-out and time-based network charges could be introduced, including to business customers.

Box 12.2 **The impracticality of regulating a time-based retail price**

It would be very challenging for a regulatory authority to appropriately calculate the regulated price of a time-based retail product. In particular:

- the price that would recover a retailer's efficient costs would change with the timing of a customer's actual consumption, which would vary from season to season and year-to-year
- the weighted price that reflects the *average* load profile of a potentially large group of consumers would be too high for some households and too low for others — in effect 'writing a cheque' from less peaky users (which typically also have lower incomes) to 'peakier' users
- since those households with peakier patterns of use would not bear the costs of their electricity use, any incentive for them to reduce their peak consumption and shift power use to non-peak times is substantially weakened. The upshot is a higher average price, reflecting the need for an inefficiently high level of investment in peak-specific capacity, which may further distort efficient consumption choices
- less peaky users on the regulated tariff could source a better deal from the retail market, so would migrate from the regulated tariff. Predicting the rate that less peaky consumers take-up market offers would be difficult, with estimates of the average consumption profile and regulated price of the group remaining on the regulated product requiring accurate information and sophisticated analysis.

Another major obstacle for implementing and administering price regulation on cost-reflective tariffs is that it would be difficult to incorporate geographic differentiation of charges into a single regulated product.

To counter these problems, the regulated price would have to:

- be set often (which would incur an extremely high administrative cost)
- increase substantially over time (which could risk government interference).

Realistically, any regulated price could only be re-weighted and calculated annually, which could lock-in significant errors. The extent of errors would depend upon the accuracy of assumptions about:

- the price responsiveness of consumers to the structure and level of time-based prices
- the representativeness of the estimated average load profile of the group of households served by the tariffs, which as noted above, would be a moving feast as consumers switched to cheaper market offers.

Even if errors were minimised, cross-subsidies and inefficient consumption behaviour would continue, driving prices higher than they should be over the longer term.

How would retailer behaviour change?

The retail tariff faced by an end-user embodies network charges, wholesale energy costs, hedging and other costs, and the retailer's margin (figure 11.1 in chapter 11). The network component is sometimes partially or completely 'hidden'. As such, the extent of demand responses by customers to more cost-reflective network pricing depends in part on the intermediary role played by retailers.

In the residential market, retailers mostly hedge the variability in wholesale energy prices on behalf of the majority of their customers. (They similarly smooth variability in energy prices for business customers, but usually to a lesser extent.) Retailers achieve such price smoothing in a variety of ways: either by hedging arrangements, through contracts with generators or, in rare cases, by taking the price risk directly themselves.

Cost-reflective network charges will have little effect on consumers if retailers do not have incentives to pass through at least some form of those time variant charges in their retail offers.

It would not be efficient (or financially sustainable) for retailers to maintain the same level of (almost universal) smoothing of time dependent network charges as they currently do for wholesale energy costs. Smoothing variability in network prices would effectively take the form of risk pooling or insurance to cover the much higher cost of peak consumption. Irrespective of whether a retail business purchased such insurance from the market or 'self-insured', commercial incentives would usually call for some degree of risk-reduction — and a passing-through of price risks to customers to correct for the moral hazard¹⁰ from high peak consumption. In the electricity market, another risk management approach in regard to network price variations might take the form of demand management. That could include some level of price exposure for customers and the availability of load management programs.

In the longer run, any incumbent retailer that maintained a business model of smoothing all variability in energy *and* network charges would risk making lower returns unless customers were prepared to pay a large premium for this service. Customers who would prefer to avoid paying such a premium would be likely to switch to another retailer who offered a discounted time-based product. Such a scenario would transpire as new retailers or competing incumbent retailers progressively offered more innovative products, which could lure customers with

¹⁰ That is, the likelihood that consumers would not seek to limit their consumption at peak times given they do not bear the associated cost.

genuine bill savings through a combination of time-dependent tariffs and demand management services to manage price risks.

The AEMC *Power of Choice* review found that retailers already generally pass through the structure of network charges in a way that closely resembles their original form. Where the network tariff is flat, it is teamed with a flat energy usage charge. If a network charge included some time-based components in the tariff, the overall retail charges also incorporated that variation.

Conversely, KPMG was sceptical about the appetite for retailers to pass through price variability in tariffs (2008). In particular, KPMG noted concern among retailers about losing customer share from complex tariff offerings. As of mid-2009, more than three-quarters of the end household customers serviced by Ausgrid's then integrated retail arm were exposed to an (untargeted) 'time of use' (TOU) network charge which followed the TOU tariff (applied by Ausgrid as a distributor). However, of those customers with an external retailer, only an estimated half of these faced TOU tariffs from their retailer of choice (Energy Australia 2009, p. 9).

The key quandary for network businesses is, in practice, what degree of demand management by retailers would materialise, since hedging and bill smoothing may distort consumption responses to cost reflective network prices. If network businesses engaged early with retailers in explaining their tariff setting process, it would allow retailers time to prepare their marketing strategies and offers to consumers and could help support a higher rate of pass-through of tariff structures to end-users.

While retailers would be free to decide how to include the relevant network tariff into their retail offer, it is expected that retailers would put forward a range of tariff offers, including, perhaps, the option of a flat tariff. However, the price of a flat retail tariff would have to reflect the overall cost of supplying an individual consumer and would need to include a premium for the 'insurance' against any price risks. (In such cases, particularly 'peaky' users could potentially face a hefty premium.¹¹) While some consumers may of course be prepared to 'wear' the extra cost of the flat tariff, many consumers would prefer to reduce future bill increases by taking up innovative retail offers that encourage consumers to shift the timing of their power use. Where beneficial to consumers, tariff options could be complemented by information (such as online access to real-time usage data and relevant charges) and technologies (such as direct load control or a home area network) to assist with energy management. Providing such technologies (and education about how to use them to respond to price signals) would represent a key role for retailers.

¹¹ This could encourage peaky users to reduce their peak consumption (and reduce their flat tariff), or transfer to a different retail tariff.

In summary, despite the possibility that some retail products offered may reduce the price exposure of consumers at peak times by some smoothing of network tariffs, the Commission expects many retailers would choose to pass through cost reflective network tariffs, resulting in more efficient outcomes. Further, the prospects of a national wholesale energy hedging market developing (chapter 18) may help increase retail competition (reducing the trends towards the ‘gentailer’ business model) and lessen any risks from the removal of retail price regulation (box 12.3).

Box 12.3 The prospect of a national hedging market will strengthen retail competition

The emergence of ‘gentailers’ (retailers that also own generation assets) as a business model to internally hedge price volatility and quantity risks raises questions about retail contestability.

Currently, hedging markets are state based with a spot price determined at each state’s regional reference node. Hedging markets are similarly confined to within state boundaries. A national hedging market could enhance retail contestability, as a new entrant retailer could more readily access financial products to manage price and quantity risks, and could use contracts with out of state generators.

Chapter 18 suggests two key changes that would help to support a national hedging market and retail contestability:

- implementation of an Optional Firm Access regime for transmission, which will support firmer hedging options across state boundaries (draft recommendation 18.1)
- the possibility of increasing the transparency of hedging positions, principally to monitor market power issues but also to better inform retail entrants. (The costs and any risks of this option have not yet been fully explored.).

Nevertheless, there is a risk that retail competition and contestability may not develop with an efficient degree of pass-through of cost reflective network tariffs as foreshadowed. If this were to occur in some retail markets, there would be an option (at that point in time, rather than pre-emptively) to require that a retail tariff took a certain form. That could be implemented under the NECF (or other jurisdictional legislation) and include:

- mandating the pass-through of critical peak network charges to ensure consumers face charges commensurate with the costs of their consumption
- placing complementary obligations on retailers to inform customers of demand management options, such as direct load control of peak intensive appliances offered by distribution businesses, or requiring retailers to provide demand management technologies and services themselves.

Such measures should only be used if it were evident that retail tariffs did not develop to offer customers a choice of products, including opportunities to pay less for the use of the network by shifting the timing of consumption. Further, a decision to implement a regulated approach should not be taken lightly given that stronger regulation of the sector is likely to suppress the contestability of the market over the longer term.

DRAFT RECOMMENDATION 12.3

Where retail price regulation exists, the Australian Energy Market Commission should review the market for effective competition.

- ***In jurisdictions where the Australian Energy Market Commission advises that retail price regulation should be removed, the relevant state or territory government should remove retail price regulation as soon as practicable.***
- ***Where the Australian Energy Market Commission advises that there is strong evidence that competitive pressures would be weak with the removal of the regulation, and could not be addressed by consumer awareness measures:***
 - ***it should suggest any structural reforms that would be necessary to develop workable competition. These reforms should be promptly progressed by the relevant jurisdictions, and retail price regulations should be removed by no later than 2015.***

13 Distributed generation

Key points

- By producing power close to the point of consumption, distributed generation can sometimes avoid or defer network investment by helping to relieve network congestion, meet peak demand or improve system reliability.
- However, the current policy environment sends opposing signals to distribution networks and customers about the economic value of distributed generation.
 - On the one hand, the capacity for local generation to substitute for network investment is constrained by regulatory obstacles, although some of these — such as a lack of information about network constraints and uncertainty about connection charges — have been, or are soon to be, substantially resolved.
 - On the other hand, government schemes to encourage renewable energy and reduce emissions have greatly increased the take-up of some forms of distributed generation, particularly rooftop photovoltaic (PV) units:
 - ... the take-up of rooftop photovoltaic (PV) units has produced minimal network savings as existing non-time varying tariffs do not encourage householders to orient units to maximise generation in periods of peak demand
 - ... the effective use of distributed generation to help reduce network investment needs to ensure that take-up is maximised in those parts of the system subject to the greatest constraints. Current subsidies do not assist that outcome (and can impose costs on network providers) and should be removed as soon as practicable.
- Current pricing rigidities discourage efficient network use in peak periods. Eliminating these rigidities by introducing cost-reflective pricing would require major reform. Together with the introduction of a carbon tax, such reform would also render redundant an assortment of inefficient distributed generation subsidy arrangements, such as PV feed-in tariffs and the Renewable Energy Target scheme.
- Distributed generation can impose costs on the network — for example, where it requires investment to meet safety and reliability standards.
 - While significant in some areas, overall this appears a relatively minor concern, and recent regulatory changes mean that medium-scale distributed generators will now bear those costs. This provides the right signals for investment.
- The immediate prospects for large network savings from the efficient use of distributed generation are low, but should rise as the regulatory obstacles to its uptake are eliminated and with technological change.
- The use of benchmarking to achieve some theoretically efficient level of investment in distributed generation by network providers is impractical and would in any case be of limited assistance in promoting efficient network costs.

Electricity supply is dominated by large generators that are remote from customers and, accordingly, must supply power to end users through a network of transmission and distribution lines. The vast network is a consequence of Australia's geography; the economies of scale in generation; the advantages of generator proximity to large low cost energy sources; and the difficulties in major cities in finding suitable space for generators. Historically, the picture was starkly different. In Sydney for example, electricity was initially entirely generated within its environs, and even in 1958 internal supply still accounted for 75 per cent of its power needs (Wilkenfield and Spearitt 2004). It is a fraction of this today.

However, new technologies and policy decisions are slowly reversing the decline in local generation. Generation close to the customer (distributed generation or DG, also referred to as embedded generation) offers the scope for locally produced power to substitute for electricity delivered from the grid (demand replacement) and supply any surplus power into the grid. DG thus offers the potential to reduce network investment otherwise needed to service peak demand. DG can also, depending on circumstances, increase or reduce the need for network augmentation to ensure the reliability of electricity supply. This is important because investments to meet rising peak to average demand and to ensure reliable supply have been major sources of cost increases in the network.

This chapter explores the role that DG might have in achieving efficient network costs. It outlines participants' concerns about regulatory and non-regulatory obstacles to its use by network providers as an efficient non-network alternative to meet system constraints, and the state of regulatory reforms to address those concerns. Finally, the chapter considers whether there is a role in the regulatory framework for benchmarking specifically to achieve an efficient level of DG use by network providers (as part of a broader aim of achieving efficient network costs).

(Chapters 11–12 cover the implications for network investment from demand management options generally.)

13.1 What is distributed generation?

There are many definitions of DG (box 13.1). Common themes, though, revolve around DG referring to generation located close to users who generally use a share of the power produced, and connected directly to the distribution network (rather than the high voltage transmission system). Chapter 10 of the National Electricity Rules defines a distributed (or embedded) generating unit as 'a generating unit connected within a distribution network and not having direct access to the transmission network'.

Box 13.1 Definitions of distributed generation

Purchala et al. (2006) identify a range of definitions, including:

- The Institute of Electrical and Electronic Engineers defines DG as the generation of electricity by facilities that are sufficiently small to allow interconnection at nearly any point in a power system.
- The International Energy Agency makes no distinction on generation capacity and defines DG as units producing power on a customer's site or within local distribution utilities, and supplying power directly to the local distribution network.

The EU Electricity Directive considers DG to include all power plants connected to the distribution system (Scheepers et al. 2007, p. 10).

In the Australian context, the CSIRO notes:

Distributed generation refers to technologies generating electricity that are located in the distribution network. Generally, the technologies are connected at low voltage (<22 kV) and in a number of cases may provide additional energy in the form of hot or cool water for a variety of applications [i.e. co- or tri-generation]. (2009, p. 94)

Sources: CSIRO (2009); Purchala et al. (2006); Scheepers et al. (2007).

DG covers a multitude of technologies: predominantly combustion engines using liquid or gaseous fuel, but also micro-turbines, solar power, wind power, biomass power and fuel cells (Ledwich et al. 2011, p. 9).

While most DG is comprised of units producing from a few kilowatts (kW) to units producing up to 10 MW, there are some DG units that produce well in excess of this. However, as noted, the defining characteristic of DG is connection to a distribution network rather than the scale of generation (Ackermann et al. 2001, p. 201). The AEMC classification of DG units according to their installed capacity is shown in table 13.1.

Electricity production from DG is usually too small to be centrally controlled or dispatched by the Australian Energy Market Operator (AEMO). However, where the supply from DG is sufficiently large or predictable (such as from industrial scale co-generation plants), it is required to be despatched into the market under National Electricity Market rules (Dunstan et al. 2009, p. 22). The general threshold for such scheduled generation is a capacity of 30 MW or greater (AEMO 2010c, p. 18).

Although DG can include generators with a capacity in excess of 30 MW, these generators face a regulatory environment similar to that for large-scale decentralised generation. Accordingly, where the Commission discusses obstacles to networks' efficient use of DG (section 13.5), this is primarily of relevance to DG with an output of 30 MW or less.

Table 13.1 Australian Energy Market Commission classification of distributed generation units

<i>Classification</i>	<i>Technical definition</i>	<i>Typical installation</i>
Micro	Less than 2 kW and connected to low voltage network	Rooftop solar PV
Mini	Greater than 2kW and up to 10 kW single phase or 30 kW three phase	Fuel cells; combined heat and power systems
Small	Greater than 10 kW single phase or 30 kW three phase, but no more than 1 MW	Biomass, small hydro
Medium	Greater than 1 MW but no more than 5 MW	Biomass, hydro, local wind generating units
Large	Greater than 5 MW	Co-generation, hydro, solar thermal. Many wind farms are distribution connected

Source: AEMC (2012e, pp. 162–3).

13.2 Scale of distributed generation in Australia

While there is no complete record of installed capacity of DG in Australia, the 2010 *Survey of Electricity Demand Management in Australia* provides a comprehensive and recent snapshot of its network incidence. That survey sought data from the 20 Network Service Providers in Australia on DG in the residential, commercial and industrial sectors within their networks. Ten network providers responded with data on DG (table 13.2). For those respondents, DG constituted 798 MW of installed capacity — with 624 MW in the commercial/industrial sectors and 174 MW of installed capacity (almost entirely rooftop photovoltaics (PV)) in the residential sector.

Since that 2010 survey, residential PV installations (stimulated by government subsidies and generous feed-in tariffs) have accelerated, with AEMO estimating total installed capacity in February 2012 of 1450 MW and noting that ‘Installed capacity is forecast to reach 5100 MW by 2020 and almost 12 000 MW by 2031’ (AEMO 2012b, p. iii).

In addition, technological change and the potential for lower costs provide scope for DG to increase its share of generation:

A rapid cost reduction in some distributed generation technologies — in particular Solar PV — has the potential to dramatically re-shape the Australian energy landscape. (Clean Energy Council 2012, p. 8)

Table 13.2 DG projects reported by responding Network Service Providers^a

Number of DGs and capacity, April 2010

<i>Organisation</i>	<i>Residential</i>		<i>Commercial</i>		<i>Industrial</i>		<i>Other</i>	
	<i>No.</i>	<i>MW</i>	<i>No.</i>	<i>MW</i>	<i>No.</i>	<i>MW</i>	<i>No.</i>	<i>MW</i>
<i>ActewAGL</i>	3 051	5.9	-	-	-	-	-	6.73
<i>CountryEnergy</i>	16 500	43			2	60		
<i>Energex</i>	40 224	77						
<i>Energy Aust</i>	25 000	45	-	-	-	-	43	268.5
<i>Ergon Energy</i>	-	-	3	3.36	-	-	-	-
<i>Horizon Power</i>	1	1.46	1	0.5	-	-	-	-
<i>Integral Energy</i>	-	-	1	1.3	-	-	-	-
<i>SP AusNet</i>	-	-	-	-	1	-	-	-
<i>Western Power</i>	4	2	1	0.012	-	-	-	-
<i>TOTAL</i>	84 780	174.36	26	37.17	3	60	43	275.23

^a This table reports 546 MW of installed capacity of the 798 MW reported in survey returns. The missing data was the result of organisations requesting no public disclosure of certain projects.

Source: Ghiotto et al. (2011, p. 18).

13.3 Potential benefits of distributed generation

The CSIRO (2009, pp. 16–28) and Dunstan et al. (2011b, p. 10) have identified a range of possible benefits associated with DG in Australia, including:

- reduced peak electricity demand
- reduced transmission and distribution network losses
- lower greenhouse gas emissions (from increased fuel efficiency resulting from the use of ‘waste’ heat in cogeneration or trigeneration or renewable energy)
- improved reliability of electricity supply, with greater energy security and improved system ancillary services.

Other possible advantages associated with DG include:

- the ease of finding sites for small generators to meet demand
- shorter installation times than for conventional generation plants
- the ability to use energy sources such as waste products or renewable resources which might otherwise have no economic use
- greater flexibility in choosing combinations of total cost and reliability that offer a better fit to the requirements of individual consumers.

Given the scope of this inquiry, the Commission has focussed only on DG's effects on network costs. However, in doing so, the Commission also considers some of the potential perverse incentives that could lead to the inefficient use of DG as a network alternative.

13.4 Effects of distributed generation on network costs

As noted, DG offers the potential to avoid or defer network investment by helping to meet peak demand, reducing network energy losses and improving system reliability, security and power quality. However, DG can also impose costs on the network, as integrating two way energy flows can cause technical and safety problems for infrastructure that was originally designed to only handle one way energy flows from large decentralised generators to customers.

Network cost implications from effect on peak demand

The most significant effect of DG on network costs arises from its potential to avoid or defer network investment that otherwise would be needed to cater for peak demand growth. This effect arises where DG power is consumed at the site of generation, replacing power that would otherwise be carried over the network. As the Clean Energy Council noted:

The benefits of ... Embedded Generation ... have been proven in a number of trials across Australia. Focussed at the distribution network level they represent significant opportunity for efficiency gains through demand reduction. (sub. 31, p. 6)

This view echoes that of Dunstan & Langham (2010, p. ii) who, in regard to the network investment in New South Wales planned for 2009-10 to 2012-13, claimed:

... much of this new investment could potentially be deferred or avoided if peak demand growth was slowed through measures such as energy efficiency, peak load management and *decentralised or local energy generation*. (Emphasis added)

The Dynamic Avoidable Network Cost Evaluation model¹ illustrates the scope for network savings that DG might provide. Using this model, Langham et al. estimated the annual marginal value of deferring network investment in capacity needed to meet peak demand growth. Their estimates indicated there were many areas where the deferral value of investment otherwise needed to supply critical peak capacity

¹ This model was developed under the auspices of the Intelligent Grid Cluster; a collaborative research venture between CSIRO and the university sector. The application of the DANCE model to network planning was supported by Sustainability Victoria and assisted through cooperation with Victorian network businesses Citipower–Powercor, Jemena Electricity Networks, United Energy Distribution and SP Ausnet

was between \$300–1000/kVA/year and where non-network alternatives, such as DG in its various forms, could provide the most efficient option to overcome network constraints (Langham et al. 2011, pp. 6–7). An example of how network businesses assess such network/non-network alternatives is provided in box 13.2.

Box 13.2 Management options to meet peak demand: Charlestown case study

In 2009, Energy Australia (EA, now Ausgrid) investigated if there were cost-effective alternatives to a \$40.5 million investment in infrastructure needed to ensure the Charlestown zone substation would have the capacity to meet expected peak demand in summer 2010-11 and summer 2011-12. EnergyAustralia concluded that if it could reduce demand by 4.9 MVA by summer 2012-13 it could defer this investment by one year and lead to savings of \$2.64 million or \$540/kVA.

It identified a range of non-network options, listed below.

Non-network options	Peak load reduction	Total cost to EA (\$NPV)	Cost to EA (\$/kVA)
Tri-generation	3.6 MVA	100 000	28
Relocatable generator 1	3.6 MVA	1 100 000	295
Relocatable generator 2	2.4 MVA	870 000	361
Relocatable generator 3	0.3 MVA	650 000	368
Lighting efficiency	0.015 MVA	70 000	470

EnergyAustralia's analysis concluded:

The preferred option is a network support agreement with a trigeneration project. An alternative ... is the use of temporary embedded generation ... These options will be developed to enable implementation for summer 2010-11 and 2011-12. (Ausgrid 2010, p. 5)

Source: Ausgrid (2010b).

Clearly, networks will only pursue DG to address capacity constraints if it is cost effective to do so. The (limited) evidence from the *Survey of Electricity Network Demand Management in Australia* reveals that, to date, other non-network options (particularly load management) have generally been more attractive than DG. That survey showed that the two reported DG projects with costs of \$223/kW/year² or less accounted for 10.8 MW of peak demand reduction whereas load management projects with costs of \$223/kW/year or less accounted for 258 MW (Dunstan et al. 2011a, p. 18).

² kW/year and kVA/year are commonly used interchangeably. In practice, 1 kVA is equal to about 0.95 kW. The formula for conversion is 'Power factor' * kVA = kW, where the power factor is a measure of the efficiency of conversion of electricity into 'work'.

However, Dunstan et al. (2011c) also provide a measure of the extent to which DG (as part of a broader suite of demand management options) might in future substitute for grid-delivered electricity and, in the process, reduce the amount of network investment. Using the Description and Costs of Decentralised Energy model,³ they aggregate the annualised capital and fixed costs of expanding peak generation and network capacity to establish the actual cost of delivering electricity from the point of production to the point of consumption.

Their results indicate that, in the period to 2020, there is the *potential* for DG to provide over 4000 MW of peak power at a lower cost than expanding centralised supply capacity (Dunstan et al. 2011c, pp. 65–8). This represents about 10 per cent of peak power requirements. Their results also highlight that commercial/industrial standby generation and co- and tri-generation are the most cost-effective DG options (with capital and fixed costs of expanding peak generation and network capacity of around \$0.3 million/MW or less) while rooftop solar PV is the least cost-effective DG option (with costs of just over \$1.5 million/MW). This compares with gas or coal fired centralised generators, where the cost of expanding peak capacity is between \$0.4 million/MW to less than \$0.6 million/MW (Dunstan et al. 2011c, p. 68).

Network cost implications from reliability and security effects

Regulatory requirements to increase reliability standards are also driving projected network investment and augmentation (chapter 13). In this arena, some DG has the potential to improve reliability and so reduce the need for network augmentation. For example, in a report commissioned by the AEMC, Futura Consulting found:

Other potential benefits [from DG] ... include enhanced reliability and security of supply. Notably, the dispersed nature of DG systems means that a reduction in output in any one generating system will not have a marked impact on overall reliability of supply. Reliability of supply is also improved because consumers are less subject to outages caused by transmission and distribution failures. This is particularly true for rural and regional consumers who can be subject to outages and voltage variations arising from their position at the end of a long distribution feeder. (2011, p. 36)

In discussions with a network provider, the Commission was told that a DG solution was more cost-effective for ensuring reliability of supply for a remote coastal town than network solutions of augmenting sub-transmission lines or duplicating the single line to that town. The network solutions would have cost in excess of \$20 million (pers. comm., 25 June 2012).

³ This model was developed under the auspices of the Intelligent Grid Cluster by a collaborative venture between CSIRO and five leading Australian universities. It also incorporates feedback from industry participants.

Further, DG can offer improved energy security through network benefits such as voltage support and reduced reactive power losses, as well as improved system ancillary services, such as black start capability and spinning reserves (Dunstan et al. 2011b, p. 10).

While there are no comprehensive estimates of network savings attributable to improved reliability from DG, discussions with distributors indicate that such savings are small relative to those from reducing peak demand.

Finally, it is important to recognise that integrating DG into a distribution network also has the potential to *add* to network costs. For example, Dunstan et al. (2011c, p. 62) note that the intermittent two-way energy flow of households with solar PV installations can cause problems for distribution networks designed to handle only one-way energy flows. For this type of DG, the AEMC has also found that issues related to voltage rise and harmonic imbalances are a concern for the network and the PV host where high concentrations of PV installations occur (Futura 2011, p. 11).

However, modelling by the CSIRO for large DG penetration on four actual distribution feeders in Australia found that while these problems exist, they are, in aggregate, unlikely to be significant in the period to 2050 (CSIRO 2009, pp. 30–1). Accordingly, any additional network investment to address these problems is likely to be relatively minor overall, although costs could be concentrated in some areas.

Moreover, the Energy Networks Association (the peak body representing electricity distribution networks in Australia) has noted that the technical problems and associated network costs of DG integration should lessen as smart grids (box 13.3) evolve and are increasingly adopted (ENA 2010, pp. 1-2; ENA 2011b, p. 7). This is particularly so for residential PV:

With electromechanical grids evolving to smart grids ... as the grids become progressively smarter more aggregation will be possible, particularly with photovoltaics (PVs), [plug-in hybrid electric vehicles] and other distributed renewable energy sources.⁴ (ETSA Utilities 2010b, pp. 4–5)

Further, the adoption of smart grids (with their ability to provide real time scarcity pricing) would facilitate demand response and distributed generation when it is most needed (Hogan 2010, p. 7).

⁴ Plug-in electric vehicles provide a storage option and, thus, the expected future increase in their use offers the potential to improve the viability of residential PV.

Box 13.3 What is a smart grid?

Building a smart grid involves transforming the traditional electricity network by adding a chain of new, smart technology. Examples of smart network components include:

- integrated communications infrastructure that enables near real-time, two-way exchanges of information and power
- smarter measurement devices (including advanced metering infrastructure) that record and communicate more detailed information about energy usage
- sensors and monitoring systems throughout the network that keep a check on the flow of energy in the system and the performance of the network's assets
- automatic controls that detect and 'repair' network problems
- advanced switches and cables that improve network performance
- IT systems with integrated applications and data analysis.

Smart technology can monitor, manage and maintain the network and enable two-way exchanges of energy and information, all in real time.

Source: ENA (2010).

13.5 Obstacles to efficient network investment

Despite recent reforms aimed at facilitating the efficient network use of DG,⁵ participants highlighted areas still of concern and where they considered further changes are needed.

Participants' concerns

The Clean Energy Council contended that there is a general systemic bias towards network supply side solutions:

Current arrangements for investment at the distribution level do not drive innovation in the physical system. In particular, widespread rollout of demand side management, demand side participation, embedded generation technologies and supporting technologies seems unlikely whilst the regulatory framework incentivises network investment instead. (sub. 31, p. 2)

⁵ For example, reforms to the National Framework for the Economic Regulation of Distribution and the National Framework for Distribution Planning and Expansion (MCE 2012a, 2012b).

Similarly, EnerNOC observed:

[Demand response] and distributed generation are effective substitutes for many types of network infrastructure. NSPs [network service providers] with efficient investment as their primary motivation would consider these on an equal footing with building new infrastructure, and choose the most efficient option. In the [National Electricity Market], this barely happens.

This suggests that there is a problem with the current regulatory framework: the overall balance of incentives seen by the NSPs do not result in them making the most efficient decisions. (EnerNOC, sub. 7, p. 2)

The AEMC noted concerns about the usefulness of existing rules regarding network planning to foster an efficient level of investment in non-network alternatives, such as DG and demand management:

Currently, Chapter 5 of the National Electricity Rules sets out a number of high level national requirements in respect of electricity distribution network planning. These requirements are general in nature and are supplemented by a range of state-based regulatory arrangements which differ significantly across jurisdictions.

As a result, there is a view that the lack of consistency and transparency associated with the current arrangements impedes efficient investment by distribution businesses and market participants. There is also a view that the current arrangements create a bias against the consideration of non-network alternatives in distribution network planning. (sub. 16, p. 4)

Participants in concurrent reviews also had concerns about the adequacy of information on system constraints that is available to inform DG investment decisions, and about the obstacles presented by complex, costly and lengthy connection arrangements (VCEC 2012, pp. 44–8; AEMC 2012e, p. 166). Participants to the Victorian Competition and Efficiency Commission (VCEC) inquiry into distributed generation also drew attention to barriers facing DG in the >100 kW to <5 MW range — after connecting to the network — in selling their surplus power into the retail market (VCEC 2012, p. 158).

EnerNOC noted that network price caps still act as a disincentive for networks to use DG as an alternative to network augmentation, despite efforts to counteract this effect (chapter 11 addresses this issue in depth):

When it comes to the use of demand-side alternatives, NSPs' incentives are also muddled by the way the bulk of their revenue comes from per-kWh charges. This means that successful DR [demand response], embedded generation, or energy efficiency (EE) projects tend to decrease the NSP's revenue and profits. (sub. 7, p. 2)

Part B of the AER's Demand Management Incentive Scheme is intended to reimburse NSPs to neutralise this effect. However, this is an awkward, inefficient approach, as each demand management project requires separate approval by the AER. As well as causing bureaucratic overhead, this leads to NSPs perceiving a risk that they will not be reimbursed. (EnerNOC, sub. 7, p. 2)

The Energy Supply Association of Australia noted that many customers, including most residential customers, still do not face price signals that reflect the cost of the electricity they use (esaa, sub 23, p. 9). Where this occurs, it inhibits customers' incentives to invest in DG as a substitute to consuming power from the grid (IPRA, sub. 36, pp. 6–7). In turn, this restricts the choice of non-network alternatives that distribution businesses might choose from when deciding how best to meet system constraints. (Chapter 10 discusses this issue in depth.)

Albeit outside the regulatory framework governing the National Electricity Market (NEM), submissions also pointed to the plethora of government schemes aimed at encouraging renewable energy and reducing greenhouse gas emissions. These schemes — which, for example, in some cases provide inefficiently high feed-in tariffs and generous allocations of Small-scale Renewable Energy Technology Certificates (the sale of which subsidises installation costs) — are stimulating excessive (and inefficient) investment in some types of DG (especially rooftop PV units):

The Businesses have experienced a greatly increased number of connection enquiries and applications in relation to distributed generation in recent years, as a result of State and Commonwealth Government climate change policies, programs and incentive schemes which seek to encourage greater investment in renewable and lower carbon intensive generation. (ETSA Utilities, Citipower and Powercor, sub. 6, p. 52)

The takeup of solar photovoltaic systems has been faster than expected due to the incentives provided by government. The perverse outcome is that these incentives have promoted the inefficient use of this technology from a network perspective, causing investment in networks rather than deferring it. (Ergon Energy, sub. 8, p. 25)

Moreover, as esaa noted (sub. 23, pp. 10, 78), rooftop PV units offer minimal savings from deferred network investment as system peak times do not usually coincide with peak sunlight and PV generation. Contemporary evidence supports this view:

A recent research paper published by Ausgrid indicated that the impact of rooftop solar on its summer peak demand has been small to date, despite the substantial take up in NSW. Using interval data from 26 744 installed solar systems over its peak demand period in early February 2011, Ausgrid noted that system peak time differed from the solar peak time, with the estimated output of the sample solar PV contributing only 32 per cent of the total installed capacity of PV during the peak period. Ausgrid indicated that there has been no network investment deferral as a result of installed PV on its network. (Deloitte 2012b, p. 55)

Recent and imminent reforms address many of these concerns, but some remain

As outlined below, recent and impending reforms to the NEM's regulatory framework appear to address many of the obstacles to the efficient network use of DG identified in submissions. However, some major obstacles remain, as do material differences between jurisdictions in the implementation of regulatory reform.

General systemic bias towards network supply side solutions

Regulators have acknowledged concerns about systemic bias to network investment in the regulatory framework governing the NEM and have introduced reforms to address that bias.

Fundamental reform began in 2008 with the introduction of national rules governing the economic regulation of electricity distribution networks. Those rules aim to balance the incentives and obligations for distribution businesses to invest in non-network alternatives (such as DG) with those for network infrastructure, and to encourage adoption of the most efficient option. The new rules require the Australian Energy Regulator (AER), when assessing distributors' expenditure forecasts, to take into account the extent to which they consider, and provide for, efficient non-network alternatives. The AER has the discretion to reject proposals for capital expenditure on network infrastructure if it concludes that non-network alternatives would be more efficient (MCE 2012a).

Poor information on network performance and investment opportunities

The AEMC is considering a rule change request that, among other things, would require distribution businesses to publish an annual planning report that provides information on network performance and planned system augmentation. This would include a requirement for distributors to identify and describe any forecast system limitations for sub-transmission assets and zone substations so that DG proponents are more easily able to identify investment opportunities (MCE 2012b).

The AEMC released a draft determination on this rule change request in June 2012 (AEMC 2012c), and a final determination is due by end September 2012. The VCEC has observed that, if adopted, this rule change would improve transparency and lead to better long-term planning to accommodate DG and would also require distribution businesses to more actively engage with DG proponents (2012, p. 76).

Some inquiry participants noted that some states already impose such obligations on distribution businesses and some network businesses already adopt this approach. For example, SP AusNet publishes a *Distribution System Planning Report* which details expected augmentation requirements for a 10 year and five year horizon, respectively. It also outlines network support payments that could be available to providers of innovative network support options (pers. comm. 15 June 2012). Similarly, CitiPower and Powercor publish a *Transmission Connection Planning Report* and a *Distribution System Planning Report* on their websites, which describe feasible options to meet forecast demand and network constraints and invite interested parties to express interest in providing non-network alternatives (ETSA Utilities, Citipower and Powercor, sub. 6, p. 47).

Complex, costly and lengthy connection arrangements

Recent and proposed reforms have sought to simplify and expedite the arrangements for DG connection to the network:

- new connection charge guidelines under chapter 5a of the National Electricity Rules
- proposals for rule changes under the Small Generator Aggregator Framework which seeks to simplify the registration of small generator projects⁶ (AEMC 2012e, p. 164)
- proposals for amendments to the National Electricity Rules for connecting DG (to streamline the connection process) (MCE 2012c).

The VCEC's final report for its inquiry into distributed generation observed that these reforms will address many of the barriers to the connection of DG (VCEC 2012, p. 93). The AEMC has expressed a similar view (AEMC 2012e, pp. 165, 168; AEMC 2012h, p. 39).

Barriers to on-selling surplus electricity from DG projects

The National Energy Customer Framework — introduced in the ACT and Tasmania on 1 July 2012 (and to be introduced in New South Wales, Victoria and South Australia as soon as practicable) — is intended to address regulatory constraints facing small to medium-scale DG in selling power surplus to their needs into the retail market (VCEC 2012, p. 159).

⁶ 'Small' in this context refers to generators that are less than 5 MW or otherwise subject to AEMO's standing exemption from registration as a generator (AEMO 2009, p. II).

Under the framework, those selling electricity (including electricity from DG) are now subject to an authorisation regime, administered by the AER. Under this regime, sellers are required to have a retailer authorisation or be exempt from the requirement. The AER has released an *Exempt selling guideline* (AER 2011c), which sets out its approach to retail exemptions and the types of exemptions it will allow.

In developing the guideline, the AER noted that distributed generators would need to apply for an individual retail exemption on a case-by-case basis. However, the AER:

... will grant exemptions in these situations where the initiative is in the long term interests of energy consumers having regard to all of the criteria and factors we are required to assess. (AER 2011c, p. 24)

While this reform aims to address retail licencing issues that might otherwise discourage DG, the Clean Energy Council (sub. 38, pp. 2–5) argued that it leaves significant obstacles unresolved and creates new barriers to DG connections. It also noted that the reform is not yet universal across the NEM, as three jurisdictions have refused to implement the new arrangements (citing customer protection as their key concern).

Misalignment between networks' profit drivers and the efficient use of distributed generation (as part of non-network alternatives more generally)

The AER has introduced a specific demand management incentive scheme⁷ to address systemic bias against non-network alternatives. In New South Wales, for example, the scheme consists of two parts: a demand management innovation allowance (that provides a payment for demand management related activities), and provision for the recovery of foregone revenue where demand management initiatives reduce electricity consumption and where revenue is at least partially dependent on the quantity of electricity sold (for example, under a CPI-X price cap). It achieves this by raising the price cap above adjustments for the consumer price index and the X factor (AER 2012b, pp. 7, 17).

However, despite regulatory reforms and schemes aimed at neutralising systemic disincentives for networks to embrace DG, the current regulatory framework still fails to align the profit incentive of network businesses with a socially efficient level of investment in DG (AEMC 2012b, p. 1). In this regard, the problem of network

⁷ This scheme includes distributed generation as per the AEMC Rule Determination, *National Electricity Amendment (Inclusion of Embedded Generation Research into Demand Management Incentive Scheme) Rule 2011 No. 11*, December 2011.

price caps acting as a disincentive to using DG identified by EnerNOC is yet to be resolved.

Options to address these failings are the subject of ongoing review by the AEMC under its Power of Choice review, a draft report on which was released on 6 September 2012.

Lack of cost-reflective pricing

The lack of cost-reflective pricing referred to by esaa (sub. 23) and IPRA (sub. 36) is an obstacle to the efficient level of network adoption of DG — although this is an issue mostly affecting DG that might be installed by residential customers and small businesses:

There is less transparency around the exact nature of prices faced by large consumers, as tariffs tend to be bilaterally negotiated, but time of use tariffs are much more prevalent for these consumers. ... For smaller businesses, some time of use tariffs are available, but tariffs are generally similar to those available to residential consumers. (AEMC 2012e, p. 57)

and

For large consumers who have a direct contract with the NSP, a capacity charge based on peak demand in a year is common ... For most consumers, NSPs charge a flat price for each unit consumed. (AEMC 2012e, p. 60)

Residential consumers and small businesses are subject to some peak/non-peak tariffs (AEMC 2012e, pp. 60–1). However, a more comprehensive use of cost-reflective pricing for these customers requires the support of governments to allow this and the widespread introduction of enabling technologies (such as smart meters). Loy Yang Marketing Management Company was sceptical of securing this support:

What is clear is that exposure to efficient prices is likely to be the most significant driver of change to end use electricity demand. However, this is unlikely to happen whilst retail price setting remains largely in the hands of [state] government. (sub. 25, p. 3)

As discussed in chapters 10–12, the Commission has recommended changes to facilitate the introduction of more cost-reflective pricing.

Government schemes promoting renewable energy and emission reductions

As noted, government schemes to encourage renewable energy and emission reductions have resulted in the rapid growth of rooftop PV units. These schemes, though, aim to encourage aggregate electricity generation (to replace the greatest

amount of electricity — and emissions — otherwise produced by fossil fuel-based generators) and have little regard for maximizing power output at times of peak demand or locating PV units in areas where network system constraints are most acute. The general absence of cost-reflective pricing compounds this lack of incentives for the efficient location and use of rooftop PV units.

While these schemes continue, factors largely outside the control of distribution businesses will drive the level of investment in PV installations in any network.

However, a recent Commission study on carbon emission policies (PC 2011d) found that rooftop PV units, supported by subsidies provided by the small-scale technology certificates under the Renewable Energy Target scheme and by state and territory government feed-in tariff schemes, are a relatively high cost option for reducing greenhouse gas emissions.

That study estimated that the implicit abatement subsidies from these schemes for small-scale PV was in the range of \$432–1042/t CO₂ (PC 2011d, p. 83). These costs were some of the highest identified in the study. Further, that study found that subsidising the installation of small-scale solar PV (through the Renewable Energy Target scheme and/or high feed-in tariff schemes) significantly increases the average costs of abatement (PC 2011d, p. 83).

The Commonwealth Government's introduction of a price on carbon should obviate the need for these schemes on abatement grounds. As the Independent Pricing and Regulatory Tribunal of New South Wales has noted:

IPART estimates that in 2012/13 the cost of complying with the RET [Renewable Energy Target] adds on average \$102, or 4.8 per cent, to an indicative regulated electricity customer's bill in NSW. This is significantly higher than was forecast when the RET scheme was amended in 2009 and 2010 ... In our view, the introduction of the carbon price and a move towards an emission trading scheme ... removes the need for the RET (and ultimately electricity customers) to continue to subsidise investment in the renewables sector. The RET is not complementary to the carbon price and does not cost effectively address any other significant market failure. (IPART 2012c, p. 1)

Moreover, rooftop PV units are also an expensive way of delivering peak power (section 13.4). Accordingly, the Commission considers that the current subsidies are inappropriate and should be phased out as soon as practicable.⁸ In practice, this

⁸ The Commission notes that the Small-scale Technology Certificates solar multiplier offered under the Renewable Energy Target scheme fell from three to two on 1 July 2012, and is due to fall from two to one on 1 July 2013 (Combet 2011).

would be likely to involve grandfathering existing subsidies and phasing in new arrangements to lessen industry disruption and consumer concerns.⁹

Some states in the NEM have already acted to reduce feed-in tariffs that were grossly in excess of the tariff for power taken from the grid (VCEC 2012, p. XXV):

- South Australia's price regulator made a determination in 2011 for net feed-in tariffs applying to small-scale solar PV, which reduced the tariff by 27 cents per kWh (to around 23 cents per kWh).
- In New South Wales, in 2012, the Independent Pricing and Regulation Tribunal recommended removing the obligation for retailers to offer a gross feed-in tariff of 20 cents per kWh for small scale solar PV units and suggested that an appropriate net tariff would be in the range of 5.2–10.3 cents per kWh.
- In Queensland, in 2012, the new government announced it will reduce its net feed-in tariff from 44 cents to eight cents per kWh from 9 July 2012.

And in Victoria, the government has recently announced a new net feed-in tariff to replace existing tariffs for rooftop solar PV, to take effect from 1 January 2013. The new tariff will provide a minimum of eight cents per kWh, which reflects the adjusted wholesale price of electricity (O'Brien 2012b).

However, realising the potential of small-scale DG (and rooftop PV in particular) to reduce network costs and so benefit all electricity consumers requires more than this. Regardless of whether governments decide to remove these current subsidies, they need to change the basis on which small-scale DG is remunerated so that it reflects the value of providing power to the local grid.

From a conceptual point of view, this remuneration should encompass feed-in tariffs that match the value of electricity produced and exported into the grid and payments that reflect the value to the network of relieving localised network constraints.

The VCEC examined this matter extensively in its inquiry into feed-in tariffs and came to the same conclusion. Its report suggested that remuneration should be delivered by net feed-in tariffs based on the wholesale value of electricity (adjusted for effects on system losses) and that the network value of DG be separately identified and paid for by distribution network service providers. It also suggested that feed-in tariff schemes continue for existing customers of those schemes until

⁹ The Climate Change Authority is conducting a review of the Renewable Energy Target scheme, and is due to report in December 2012. The Commission will be mindful of the review's findings in its final report.

those schemes expire, but be closed to new entrants within a specified time, and that a new feed-in tariff scheme (based on the wholesale value of electricity) be established to replace those discontinued schemes (VCEC 2012, p. XXI). The Commission endorses these suggestions.

Reimbursement on this basis would provide households with price signals that would better encourage the installation of rooftop PV units that maximized power output at times of peak demand and in areas where alleviating network constraints is most beneficial.

While remuneration along these lines could be expected to emerge should the cost reflective pricing envisaged in draft recommendation 11.2 be introduced, in practice, introducing such pricing depends on the rollout of enabling technologies (chapters 10–11) and, thus, is not likely in the near term. Changing feed-in tariffs to approximate the value of providing power to the grid at peak and non-peak times is, however, not hostage to any such rollout and could be introduced for new rooftop PV units relatively quickly. Introducing a separate payment by distribution businesses for the network value of DG is more problematic as this value will be time and location specific — although, as the VCEC noted, the AER’s price reset process might be a vehicle to identify and permit such payments (VCEC 2012, pp. 85–6).

DRAFT RECOMMENDATION 13.1

Governments should, as soon as practicable, discontinue subsidies for rooftop photovoltaic units and other forms of distributed generation delivered via feed-in tariffs, and the small-scale component of the Renewable Energy Target scheme.

State and territory governments should change the way small-scale distributed generators are reimbursed for exporting power into the grid. This would involve:

- ***feed in tariffs that approximate the wholesale price of electricity at times of peak and non-peak demand***
- ***arrangements that provide for direct payments from distribution businesses to distributed generation providers, which reflect the network value of their distributed generation capacity and output.***

To provide a transition to the new arrangements, current feed-in tariff schemes should continue for existing customers until the end of their contract period or until those schemes expire (whichever is earlier), but be closed to new entrants one year from the governments’ formal acceptance of this recommendation. Prior to that date, state and territory governments should develop replacement feed-in schemes with tariffs that approximate the wholesale price of electricity.

13.6 Benchmarking to achieve efficient levels of network use of distributed generation

EnerNOC argued that network businesses should make more use of demand-side measures (of which DG is part) to meet peak loads. It noted that the top end of the load duration curve is most efficiently addressed through these means (sub. 7, p. 4) and, following from this, called for benchmark standards to achieve some target level of investment in demand response options to meet peak demand:

We would advocate explicit benchmarking of [network service providers] on the proportion of the extreme peaks in demand they face that they address through [demand response options], instead of by building infrastructure. (sub. 7, p. 4)

For benchmarking to be a practical regulatory tool for fostering an efficient level of network usage of DG it must satisfy four conditions:

- it would need to be feasible to identify an efficient level of network investment in DG
- benchmarking some level of investment in DG would need to be consistent with efficient network investment generally
- network businesses would need to have substantial control over the level of DG connected to their network
- ‘like with like’ comparisons would need to be possible.

In practice, none of these conditions is satisfied.

Identifying some theoretically efficient level of network investment in DG to serve as a benchmark for networks to achieve is not practical as the level and form of DG connected to networks is not within the control of distribution businesses. This is exemplified by the substantial and growing residential uptake of PV units and the City of Sydney’s plans to supply 70 per cent of that local government area’s electricity needs by 2030 (City of Sydney, sub. 39, p. 2).

Despite major actual and impending reforms to the regulatory environment, there are still significant regulatory obstacles inhibiting network businesses’ use of DG. Further, these obstacles are not uniform across all jurisdictions in the NEM. Until these obstacles are resolved and networks in all jurisdictions face consistent incentives to use DG, setting a standard level of efficient investment in DG is not realistic.

Factors outside the NEM’s regulatory arrangements also exert a material influence on investment in DG (notably, a general lack of cost-reflective pricing and schemes that subsidise rooftop PV units). These factors, too, vary markedly between

jurisdictions and effectively preclude identifying some optimally efficient level of DG that networks should aim to implement. As the esaa noted:

... it is a tall order for a [distribution network service provider] to forecast the efficient level of expenditure ... when they do not have control over the take-up of distributed generation. Changes in both federal and state and territory government policies for subsidising small-scale PV have in recent years driven a rapid boom in PV installation followed by a strong deceleration as the policies were scaled back or withdrawn at short notice. Planning for such policy changes is challenging. (sub. 23, p. 11)

Moreover, setting a benchmark standard for the level of network investment in DG introduces a bias for DG as a solution to system constraints rather than allowing options to be chosen on their merits. This approach is inconsistent with a regulatory regime aimed at fostering network behaviour to deliver efficient costs.

As noted, distribution businesses have limited control over the level and form of DG within their networks. In these circumstances, benchmarking would be of little value in identifying ‘efficient’ behaviour with regard to optimal network investment in DG.

Finally, because the obstacles and incentives to invest in DG materially differ in each jurisdiction, ‘like with like’ network comparisons are not possible. Under such conditions, benchmarking networks’ investment in DG would be ineffective as a regulatory tool for achieving efficient network costs.

While this specific benchmarking is not warranted, there is a role in the regulatory framework for a broader approach to benchmarking to achieve efficient network investment and efficient network costs (chapter 8).

14 Building a reliability framework in order to benchmark

Key points

- Reliable power services are essential for both households and industry. Even short and infrequent outages can have significant economic and social costs.
- Standard forms of incentive regulation reward cost efficient network businesses with greater profits — mimicking the working of competitive markets. However, given network quality is not always easily identifiable, this can also create incentives for businesses to lower costs by reducing reliability.
- To counter these incentives, regulated standards apply to reliability and other aspects of service quality.
- Setting efficient reliability standards requires balancing the benefits to consumers of fewer and shorter power interruptions with the costs to network businesses of building and maintaining a more reliable network.
 - Reliability standards which do not reflect this balance — whether set too high or too low — can be economically costly, even if the standard is delivered cost efficiently by a network.
 - Standards that vary across networks and businesses, without good reason, can also impose significant costs on network providers and consequently on power consumers (see chapters 15 and 16).
- Setting efficient standards requires accurate measures of the value that customers place on reliability. Current estimates are inadequate and more frequent and comprehensive studies should be undertaken to improve them.
- Benchmarking of network businesses' managerial performance as part of the incentive regulation regime would need to consider any continuing differences in reliability frameworks between jurisdictions.

Though the overall quality of electricity supply is a reflection of several factors, including safety and the level and consistency of voltage and frequency, the reliability of supply is a critical consideration. The precise meaning of 'reliability' can be context dependent (see box 14.1), but in general terms it relates to the likelihood that customers will be able to access power when they need it. Poor reliability — whether through frequent small, or occasional larger, power outages

— can impose significant costs on households, businesses and the community more generally.

Box 14.1 Useful definitions

Discussions of reliability often use different terms and phrases to describe the same concepts or outcomes. Below are the definitions of the terms used in this report.

- **Quality:** quality of electricity supply collectively reflects a range of factors, including reliability; voltage and frequency levels; consistency and stability; and safety.
- **Reliability:** reliability can be expressed in the positive or the negative. Thus, it can be used to describe the likelihood that customers will experience power interruptions, with reference to the number and/or duration of those interruptions. Alternatively, reliability can be used to describe the probability of a network, or part of a network, including one or more pieces of equipment, delivering electricity at any place and time at which it is demanded. In this context, the term ‘security’ is sometimes used instead of reliability.
- **Failure:** an equipment failure is when a piece of equipment as part of a network stops working.
- **Fault:** a fault is when a network, or part of a network stops working due to the failure of one or more pieces of equipment. A fault can, but does not necessarily, lead to an interruption to power supply.
- **Outage:** an outage is when power supply to customers is interrupted. It can also be referred to as a power outage, power interruption, or blackout. Outages are often caused by failures and faults.
- **Contingency event:** a contingency event is an event affecting the power system that the Australian Energy Market Operator expects would be likely to involve the failure or removal from operational service of one or more generating units and/or network elements.
- **Redundancy:** redundancy involves the duplication of critical components to create excess capacity in a network to reduce the likelihood that a fault or failure causes an outage to occur.
- **Satisfactory operating state:** a satisfactory operating state requires all network elements to be loaded within their ratings.
- **Secure operating state:** a secure operating state requires the power system to be in a satisfactory operating state and to be able to return to a satisfactory operating state following the occurrence of any credible contingency.

Both transmission and distribution businesses endeavour to deliver reliable electricity supply by planning, maintaining and operating their networks to minimise power outages. For instance, network businesses build extra capacity (or redundancy) into their networks to ensure ‘adequate and acceptable continuity of

supply in the event of failures and forced outages of plant, and the removal of facilities for regular scheduled maintenance’ (Billinton and Allan 1996, p. 1).

Governments and regulators also impose standards to ensure that network businesses maintain high levels of reliability, the costs of which are ultimately paid by customers. As the usual market mechanisms that allow customers to trade off the value of reliability against its costs are largely missing, it is important that the standard-setting process emulates those mechanisms.

This chapter outlines the key concepts germane to discussions of reliability, and maps out a framework that can be used to identify what constitutes an efficient level of network reliability. This framework is then used in the two following chapters to assess the efficacy of the reliability arrangements currently applying to Australia’s transmission and distribution networks and how they might be improved.

14.1 What issues does reliability raise?

More than sixty years ago, Giuseppe Calabrese (1947) wrote that:

... a fundamental problem in system planning is the correct determination of reserve capacity. Too low a value means excessive interruption, while too high a value results in excessive costs. (p 1439)

Calabrese’s analytical methods for testing reliability are still relevant today (Manohar 2009, p. 15), though their application has become far more complex as networks have become bigger and more interconnected, technologies have advanced, and the demand for power has increased considerably. The importance of reliability in electricity networks has also increased and with it, the contribution that reliability makes to required capital and operating expenditure of network businesses.

Participants in this inquiry have stated that reliability has been one of the major sources of network price increases in recent years, and have attributed this in some cases to changes in reliability standards and the costs of meeting standards as peak demand grows. The higher the standard, the more redundancy and maintenance is required on the network and the higher the capital and operating costs involved. There are also significant inter-jurisdictional variations in licence and regulatory requirements for reliability (see chapters 15 and 16), which impose additional costs on network businesses and ultimately on customers.

As discussed in chapter 1, the use of benchmarking in incentive regulation to encourage managerial efficiency must account for factors outside the control of businesses, including variations in standards set by governments and regulators.

Controlling for variations in such standards also provides a direct measure of the cost implications of those differing standards. More broadly, to the extent that it is possible to identify an efficient standard that appropriately represents the preferences of customers (a benchmark in its own right), there will then be a basis for informed reform of standards — and, in particular, one freed from the political pendulum of expressions of concern about the costs of reliability and the aversion to particular instances of unreliability (such as widespread and extended, but rare, blackouts).

The influence of reliability settings on the way that electricity networks are operated, planned, and regulated is well recognised, and has prompted several reviews since the National Electricity Market (NEM) was established. Significant current and recent reviews include the:

- Australian Energy Market Commission (AEMC) Review of Distribution Reliability Outcomes and Standards — New South Wales Workstream (current)
- AEMC Review of Distribution Reliability Outcomes and Standards — National Workstream (current)
- AEMC Transmission Frameworks Review (current)
- AEMC Transmission Reliability Standards Review (updated 2010)
- AEMC Review of National Frameworks for Electricity Distribution Network Planning and Expansion (2009).

These reviews examine some of the major questions relating to reliability in the NEM, such as whether:

- in a national market for electricity, there is merit in developing nationally consistent frameworks for expressing, delivering and reporting on reliability in transmission and distribution networks
- current approaches to setting reliability standards in different jurisdictions are appropriate and whether customer preferences should play a bigger role in determining the nature of those standards
- the range of parties involved in setting standards in different jurisdictions is appropriate and, if not, what alternatives exist?

These reviews also provide valuable insight into the many levels of complexity of reliability in electricity networks including:

- physical constraints of a network, especially a network that is part of an interconnected market as large as the NEM

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- the special characteristics of a reliable network, including that some aspects of its reliability are not easily observable and some important variables are outside the control of the businesses (for example, storms and faults in adjoining networks)
 - the degree to which it is possible to identify the future risks of unreliability posed by underinvestment, network design problems, poor maintenance, or inadequate planning.

Several inquiry participants have emphasised the important effects of reliability standards on costs, and the obstacles to effective benchmarking posed by different standards.¹

Three themes emerge from the discussion above, which inform this and the following two chapters:

- reliability standards are a significant driver of costs for network businesses and lie largely outside their direct control
- the stringency of reliability standards affects customers through, on the one hand, its impact on electricity bills and, on the other, its influence on power interruptions. Cost–benefit analysis of levels of standards should take proper account of this trade-off
- regulatory settings within which reliability standards sit affect whether and how businesses deliver reliability, and have implications for efficiency in the NEM. As an example, the degree of jurisdictional intervention in specifying different reliability standards across the NEM can have implications for the overall level of efficiency.

14.2 Reliability under incentive regulation

Revenue (and pricing) caps employed in economic incentive regulations (chapter 5) aim to encourage profit-motivated businesses to lower their costs below those used to set the regulatory caps, and to take the residual as profit.

Absent quality standards, one way to lower costs would be to reduce service quality, especially as the quality of networks is only partially observable. For instance, it can take some time before degradation of the physical infrastructure or insufficient investment in new capacity shows up as poorer reliability. Moreover, because network businesses do not operate in a competitive market, they do not face the

¹ These include ETSA Utilities, CitiPower and PowerCor Australia (sub. 6, pp. 43–4), Ergon Energy (sub. 8, p. 10–11) and the Energy Networks Association (sub. 17, p. 30).

usual commercial pressures to meet consumers' preferences for the trade-off between price and quality.

The consequence is that, under standard economic incentive regulations alone, network businesses would most likely underinvest in reliability. For example, by reducing maintenance, a network business could cut its operating costs, and at first glance, might appear to be more efficient. Possible consequences such as trees growing up against lines or the failure to replace ageing poles would not be apparent to most customers until they caused power interruptions (box 14.2). Overseas experiences (discussed in chapter 15) show this is more than a theoretical notion. Indeed, deteriorating reliability will eventually result in more and longer interruptions, thereby escalating costs for customers and the wider economy.

It is important to recognise, that notwithstanding the natural monopoly characteristics of network businesses, there will be some 'market' constraints on the scope for degradation in reliability under incentive based price regulation (box 14.2). There is also a range of instruments that can be used to encourage higher reliability, involving different degrees of balance between prescription on how reliability outcomes are to be achieved and penalties for failing to meet reliability outcomes.

Suffice to say that the incentive regulation framework for the NEM is complemented by a range of reliability standards governing the planning, operation and performance of transmission and distribution networks (chapters 15 and 16 respectively). Standards also apply to other aspects of quality including the consistency and level of voltage and frequency, and safety. As noted in the following two chapters, these standards currently differ from one jurisdiction to the next and, in the case of distribution, even from one business to the next within a jurisdiction.

14.3 The costs of reliability for network businesses

It is costly to build, operate and maintain very reliable networks. There are various dimensions and trade-offs involved in this task.

- Network businesses build redundancy into their networks so that in the case of a wide range of contingencies, customers will not experience an interruption to supply. For example, most transmission lines in the NEM can continue to supply the load demanded even when an element of the network, a line or transformer for example, fails. Failures, especially for transmission lines, are rare — according to AEMO (2010d, p. 14) single lines are effectively available

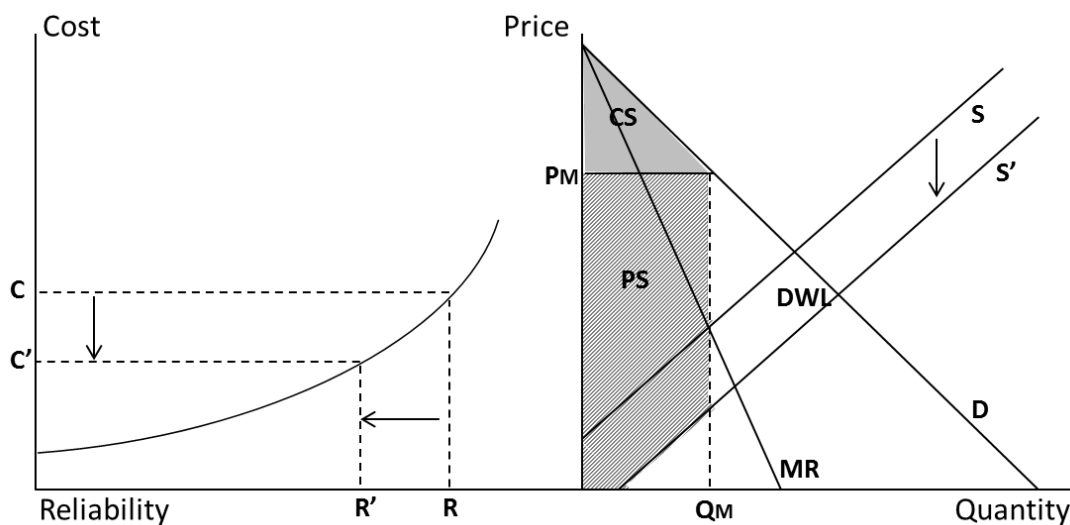
99.98 per cent of the time. This implies that there must be backup (redundancy) for only around one hour and 45 minutes a year.

Box 14.2 How do changes in reliability affect efficiency?

The figures below show the relationship between the level of network reliability and the costs of network supply. The figure on the left depicts a cost/reliability curve where decreasing reliability leads to lower costs per unit of supply. The figure on the right is a standard demand (D) and supply (S) curve depiction for electricity.

The effects of the incentive to reduce reliability under incentive regulation (and without reliability standards) can be depicted as a downwards shift in the supply curve of a business (S to S' in the figure to the right below). The shift arises from the network business moving down the cost/reliability curve (as shown in the figure to the left below).

Under this scenario, the price remains unchanged because it is regulated (P_M) and as customers cannot immediately observe the deterioration in quality and adjust their demand. Consumer surplus (CS) also does not change.



However, the business makes more profits (or increased 'producer surplus' (PS)), equivalent to the shaded area between the two supply curves. Even in the absence of regulated standards, there is a limit to how far businesses could let reliability decrease. Consumers would eventually experience interruptions, and alter their demand accordingly. For example, they might purchase a supplementary source of energy (such as gas for heating and cooking, or generators). Even so, the imposition of regulatory standards may be a more efficient solution. These could take several forms, including prescriptive technological standards; economic incentives to set efficient levels of reliability by introducing rewards (penalties) for exceeding (falling short of) reliability targets; or allowing an independent body to monitor and enforce quality outcomes.

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- As the operator that dispatches electricity around the NEM, the Australian Energy Market Operator (AEMO) is constrained in the load that it can dispatch down a line by the equipment ratings on the line.² For a network business, although lower ratings lessen the likelihood of faults from overheating on lines, and thereby increase reliability, lower than necessary ratings artificially constrain the way that generators can be dispatched, potentially leading to higher than necessary costs for generated power.
 - Consistent maintenance of network infrastructure reduces the probability of faults occurring. Maintenance can include removing the dust that gathers in insulators and can cause fires, and cutting trees that are too close to lines.
 - Actions to increase reliability can also be taken after a fault has occurred, both to limit the spread of the outage to other customers and to fix the problem quickly to restore the power. To respond quickly to faults, network businesses use sophisticated monitoring and relay equipment to alert operators when and where a fault occurs, and they ensure maintenance crews are ready to be dispatched as soon as they are needed.

All of these measures are intended to avoid outages and, where they do occur, to minimise their effects on customers. In a well-managed network, the likelihood of a serious interruption to supply should get smaller (reliability gets better) the more a network business invests in physical, operational and maintenance capacity.

Businesses can address some causes of outages easily and cheaply. For example, one business indicated that a large number of its faults had previously been due to animals climbing into equipment. Subsequent installation of inexpensive animal guards on the equipment had reduced such faults considerably. Other causes of outages cost more to address, for example, maintaining easements and clearing vegetation from under overhead lines.

More generally, at a broad level, the higher the level of reliability, the more costly it is likely to be to achieve further improvements. For example, it is nearly impossible to build a network that retains reliability following extreme weather events. Undergrounding lines might largely avoid faults from weather events but only at a very high cost and, even then, the lines would be vulnerable to being accidentally dug up. Also, the incremental costs for businesses of improving reliability are likely to differ across large networks such as the NEM due to weather, terrain, network length and network density (Jamash et al. 2010).

² Line ratings limit the proportion of the maximum capacity of a line that can be used under different ambient conditions. For example, when the weather is cooler and there is more wind lines have higher ratings (more capacity) because they do not heat up (and then sag) as much.

While network operators will have a detailed knowledge of the costs and means to increase reliability, governments and regulators are typically less well informed. Without good information or sufficient resources to access expertise, governments and regulators will not be in a good position to make judgements about the costs of maintaining or improving reliability (let alone to set those costs against the benefits delivered for customers). This information asymmetry is one justification for benchmarking (and associated information collection), since it makes the cost differences and their sources — including variations in reliability standards — more transparent. (It may also be another justification for the use of the Regulatory Investment Test for Transmission (RIT-T) as a transparency tool, and the involvement of an independent expert body — AEMO — in planning (an issue discussed in chapter 15).)

More specifically, benchmarking network businesses may shed light on instances where a business has used innovative strategies to meet reliability standards. Any benchmarking with a reliability focus would of course need to take account of the divergences in reliability standards that apply across the NEM. Even so, with the potential benefits from even modest efficiency gains in meeting expensive reliability standards being large, a well-constructed benchmarking regime could be highly worthwhile.

Expressing reliability standards in a consistent way under NEM-wide frameworks for transmission and distribution networks has the potential to make any benchmarking task easier. The AEMC (2010a, 2012i) has recommended national frameworks for reliability for transmission and distribution. A national framework for the expression and application of, and reporting on reliability standards in transmission has progressed further, with the AEMC considering the implementation of such a framework (MCE 2011). A national framework for reliability standards for distribution is also currently under review (AEMC 2012i).

Notwithstanding the benefits that consistency in the expression of standards to facilitate benchmarking might have, it will not address the concern that the standards themselves might not be optimal. Because the cost of an increase in reliability will ultimately be included in customers' bills and the costs of low reliability will also be borne by customers suffering interrupted electricity supply, regulators should carefully consider the incentives network businesses have to meet standards efficiently, as well as the settings of the standards themselves.

14.4 What level of reliability is efficient?

Just as customers value the quality of physical products differently, so too will they place different values on ‘reliable’ electricity supply. In competitive markets, the determination of the efficient level of quality is often left solely to the interactions between many suppliers and many consumers. If the market for network reliability were competitive, customers who had a strong preference for reliability could choose a more reliable service with a correspondingly higher price and vice versa. And if the service, including its reliability, was not good value for money then a customer could switch to an alternative provider.

However, electricity networks in Australia do not operate in a competitive market; customers cannot change their network service provider without physically moving to an area operated by a different network business. The natural monopoly characteristics of electricity networks mean that, without regulation, businesses would face relatively few of the usual market disciplines in setting prices and levels of quality. As noted earlier, this is why both price and quality/reliability regulation is required.

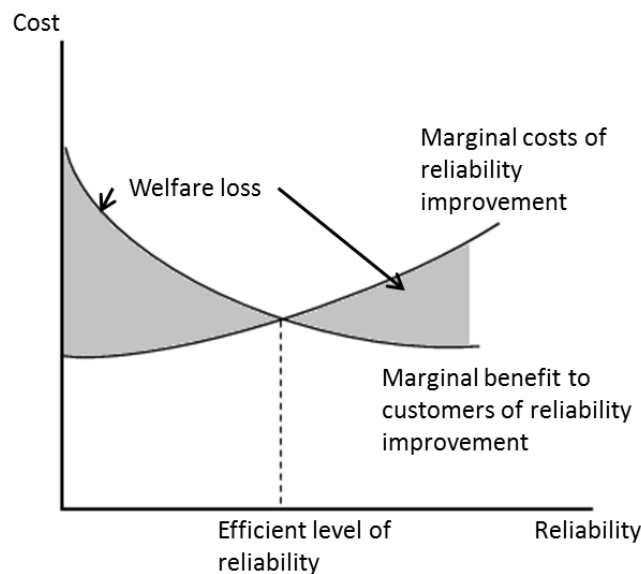
From an efficiency perspective, the level of reliability pursued through regulation must have regard to both the rising incremental costs and the diminishing value of greater reliability (box 14.3). These costs and benefits vary, depending on the type of customer, time of interruption, geographical location, and climate. Hence, to set appropriate standards, regulators need detailed and accurate information about the cost functions of businesses and the value of reliability for customers.

14.5 Measuring the value of reliability

Estimating the value to customers of the reliability of electricity supply is challenging. As customers cannot choose between network businesses offering different levels of reliability at different prices (or indeed between services of different quality offered by the same business), they cannot reveal directly how they value reliability. This problem is not isolated to electricity. Governments often set or require standards where consumers cannot directly observe quality (such as qualification standards for surgeons). Where markets cannot be relied upon to determine trade-offs between reliability and costs, regulators must use indirect methods to set an efficient standard.

Box 14.3 Identifying the efficient level of reliability

The figure below depicts the efficient level of reliability for a network. The upwards sloping curve represents the rising marginal costs of providing a more reliable network. The downward sloping curve represents the benefits to customers of improvements in reliability. The optimal outcome is where the marginal cost of providing an extra 'unit' of reliability is equal to its marginal customer benefit.



Sources: Jamasb et al. (2010); Ajodhia and Hakvoort (2005).

On the customer side, the usual approach is to try to estimate the benefits of greater reliability as the avoided costs of power interruption. These costs depend on the characteristics of the customer:

- Costs for commercial customers might include lost production and sales, reduced reputation for reliable product delivery, the costs of re-starting equipment, food spoilage, off-specification production, and equipment damage. Even brief outages can be costly, if machines take a long time to restart (MEU 2011b, p. 19).
- Costs for residential consumers are more difficult to quantify since they include nuisance and subjective costs that are not priced in markets, such as resetting clocks, lost work on computers, changing plans, fear, anxiety and coping with inconvenience.

Costs can also differ within customer groups across locations. For example, residential customers in rural settings, who are more accustomed to experiencing interruptions, may incur lower costs since they are better prepared to cope (for instance, by having an emergency generator). And the same customer can incur different costs depending on the time of the interruption; how hot or cold the day is; and the duration of the interruption.

There are also broader social costs of power interruptions, such as an increase in road accidents, or disruptions to telecommunications or public transport. A widespread and long lasting power outage in Sydney, for example, might also damage its international reputation.

How precisely is the value of reliability to customers estimated?

The costs to customers of interruptions can be estimated in several ways, such as the value of unserved energy (in dollars per kilowatt).³ Other measures seek to map the costs incurred by customers according to interruption duration, recognising that these costs might not be linearly related to the amount of energy unserved. A large commercial customer, for example, might incur the majority of costs during the first five minutes of a fault, after which costs increase only slowly.

Such changing cost patterns can be captured in Customer Damage Functions (CDF), calibrating the cost of being without power as a function of the duration of the interruption. CDFs for individual customers can then be aggregated to the sectoral level to form a ‘sector customer damage function’ (box 14.4). By way of illustration, sector CDFs suggest that customers in agricultural industries experience costs of around one dollar per kilowatt for an interruption lasting one minute.

Estimates of values of customer reliability in Australia

Most Australian estimates of the customer value of reliability are based on surveys conducted in Victoria. Monash University conducted the first survey in 1997 using direct survey methods and Charles River Associates (CRA) updated these results in 2001 and 2007 (AEMO 2010e, p. 14). Termed the Value of Customer Reliability (VCR), AEMO uses these estimates when setting and advising on reliability standards in Victoria and South Australia respectively. AEMO updates the measures annually, indexing them to Victorian income measures (AEMO 2010e, p. 10).

³ Unserved energy is the amount of electricity demanded by customers that is not delivered due to interruptions over a given period.

Box 14.4 Estimating ‘customer damage functions’

A customer damage function (CDF) describes the relationship between the costs incurred by electricity consumers and the characteristics of faults. Interruption costs reflect:

- interruption attributes: duration, season, time of day, day of the week, time of the year
- customer characteristics: customer type, customer size, business hours, household family structure, presence of interruption sensitive equipment, presence of back-up equipment
- environmental attributes: temperature, humidity, storm frequency and other climatic conditions (Sullivan and Keane 1995).

CDFs require various information on the costs that consumers bear when faults occur. There are two main approaches for collecting this information — models and survey evidence. Model based approaches include gross national product per kWh of electricity consumed; wage income per kWh consumed; and the cost of a stand-by generator (Ajodhia and Hakvoort 2005 p. 219; Oakley Greenwood 2011, p. 4).

Survey based approaches include:

- estimates of the direct costs of an interruption (for example, lost sales of businesses, or wages paid to staff unable to work) and also sometimes the costs that customers take to avoid, or to prepare for, interruptions (Oakley Greenwood 2011, p 5)
- estimates based on the economic cost of substitution, which ask customers to choose from a given list, the actions (and their costs) they would be most willing to undertake
- contingent valuation surveys, which assesses customers’ willingness to pay to avoid interruptions or willingness to accept more or longer interruptions
- ‘conjoint’ analysis, which asks customers to pick or rank service/price bundle options, and sometimes to indicate the extent to which they prefer one option over another (CIE 2001; Oakley Greenwood 2011).

In general, model based approaches are cheaper and easier to undertake because the data usually already exist. Survey approaches take longer and are more complex.

CDFs can be more than two dimensional if they map the costs of different types of user to interruptions of varying durations at different times of the day and days of the week. CDFs will be more accurate the more information they embody about variations in customers, and the costs incurred from variations in interruptions.

AEMO has also used data on the energy usage of different industries to estimate values in the other jurisdictions in the NEM (table 14.1).

Table 14.1 AEMO estimates of the value of customer reliability in the National Electricity Market

\$AUS/kWh

Year	NSW	Vic	QLD	SA	Tas
2007	35.08	50.26	37.20	38.04	42.02
2008	37.53	52.94	40.13	40.06	45.69
2009	40.07	56.18	42.00	43.12	48.44
2010	41.53	57.29	44.31	44.30	50.97

Source: AEMO (2012c).

ACTEW Corporation and ActewAGL commissioned NERA and ACNielsen to measure customers' willingness to pay for increased reliability in the ACT. The results are not directly comparable to those presented in the table above but are on average lower (NERA and ACNielsen 2003). In South Australia, survey evidence found that customers were generally unwilling to pay for higher levels of reliability except in areas where service was considered relatively poor (ESC 2005, p. 33 and KPMG 2003). The AEMC reports a VCR in New South Wales of around \$95 per kWh from a survey conducted by Oakley Greenwood (2012) using the same basic approach used for AEMO's estimates. This survey also reported VCRs for each of the state's distribution businesses. These were \$87, \$111 and \$91 for Ausgrid, Endeavour Energy and Essential Energy, respectively (AEMC 2012i, p. iv).

How good are the available measures?

The estimated VCRs for Victoria and New South Wales unsurprisingly reveal higher burdens of interruptions for commercial customers compared with those for households. Both report similar values for households of around \$20 per kWh (table 14.2). However, there are large differences in the estimated values for commercial entities which are the source of the sizeable difference between the overall weighted average cost for these two jurisdictions.

The differences may reflect methodological variations, different customer categories (and the sample weights associated with them), and increased reliance of smaller service businesses on computerised ordering, accounting and management systems, electronic payment processing and the use of the internet. However, it is unlikely that small business expectations of reliability have changed substantially over the short period concerned (and certainly, this does not appear to be true for households).

Table 14.2 Sectoral values of customer reliability for Victoria and New South Wales, 2012^a

\$/kWh

<i>Sector</i>	<i>Vic VCR (AEMO)</i>	<i>Sector</i>	<i>NSW VCR (AEMC)</i>
Residential	23.80	Residential	20.71
Agricultural	130.26	Small business	413.12
Commercial	103.77	Medium-large business	53.30
Industrial	41.24		
Weighted average	57.88	Weighted average	94.99

^a The weighted average Victorian VCR is higher than the figures in table 14.2 because it has been indexed to 2012.

Source: AEMC (2012i, p. 42).

VCRs in Australia are generally high by international standards (tables 14.3). In representations to AEMO's Review of National Value of Customer Reliability (2012c), Visy (2011, p. 2) and the Major Energy Users (2011b, p. 4) have also questioned whether the Victorian VCRs are excessive. PIAC (2012) made similar observations about the estimates of the VCRs in New South Wales.

The US results (table 14.4) show that the cost per unserved kWh falls the longer the interruption lasts for all types of customer — a pattern likely to apply to most, though not all, customers in Australia.

Table 14.3 International measures of value of customer reliability for comparison

<i>Region</i>	<i>Sectors</i>	<i>Origin value</i>	<i>Year</i>	<i>\$AUS (2009)/kWh</i>
Sweden	Residential	Kr 61.16	2004	13.00
Chile	Industrial	\$US 0.22	1989	0.49
Indian States	Industrial	Rs 24.71	2001	1.35
Thailand	All	60 Baht	2000	3.22
France	All	\$US 3.60	1988	7.96
NE USA	All	\$US 4.11	1977	15.84
Netherlands	All	€ 8.56	2001	17.98
Great Britain	All	£ 10.00	2006	26.09
Ontario	All	\$US 10.00	1980	33.00
NW USA	All	\$US 16.93	1990	36.57
Ontario	All	\$US 17.00	1989	37.58
USA	All	\$US 33.01	2008	37.63
Ireland	All	€ 40.00	2005	76.39
New Zealand	All	\$NZ 20.00	2011	16.00

Sources: Hickling (2010, p. 11); New Zealand Electricity Industry Participation Code, Schedule 12.2.

Table 14.4 Estimated values of customer reliability in the US by customer type and duration (for a summer weekday afternoon)^a

\$US (2008)

<i>Interruption Cost</i>	<i>Interruption Duration</i>				
	<i>Momentary</i>	<i>30 minutes</i>	<i>1 hour</i>	<i>4 hours</i>	<i>8 hours</i>
Medium and large commercial					
Cost per event	11 756	15 709	20 360	59 188	93 890
Cost per unserved kWh	173	39	25	18	14
Small commercial					
Cost per event	439	610	818	20 696	40 768
Cost per unserved kWh	2401	556	373	307	218
Residential					
Cost per event	3	3	4	8	11
Cost per unserved kWh	22	4	3	1	1

^a These data are from a meta-analysis of VCRs for different regions in the United States. An average residential household in New South Wales uses about 0.83 of a kWh in one hour of energy usage. The most comparable results in this table to the NSW results are in the column representing an interruption of one hour.

Source: Sullivan et. al. (2009, p. xxi).

From a methodological perspective, the existing Australian data seem to have several major flaws. The surveys ask customers to estimate the cost of interruptions were they to occur at the worst possible time (Visy 2011, p. 2; AEMC 2012c, p. 41). This will produce an upwardly biased estimate given that outages may occur at any time. An appropriate model would consider the costs of events of all kinds, taking into account risk aversion. A second major flaw — which produces an opposite bias — is the lack of a measure of the costs of momentary interruptions (AER 2011d, p. 2).

A third critical limitation is that the studies only provide a point estimate of the VCR, when the value will vary for different levels of reliability and across many more customer categories than the few identified in the current studies. Indeed, this is the intention behind estimating CDFs described above. It would therefore be desirable if, unlike its current practice, AEMO were to use different VCRs to assess whether investments should be made in places where interruptions are common and long-lasting, and/or in places where interruptions are rare and short-lived. If the downward sloping curve, representing this relationship in box 14.3 were very flat meaning that the per unit costs of interruptions did not decline much as the duration or frequency of outages increased, a point estimate of the VCR might be a reasonable approximation. However, the characteristics of the relationship are an empirical question requiring more frequent and extensive research.

Theoretically, a single VCR also fails to account for differences in the mix of customers affected by an investment for reliability. For example, a line servicing an area in which there are large industrial or mining customers is likely to be valued differently to a line to an area that is largely agricultural. AEMO uses the same weighted customer costs in areas with different customer profiles.

And there are also issues with the methodologies that underlie the sort of measures referred to above. A common finding in the extensive literature on contingent valuation is that respondents' willingness to accept is around three times their willingness to pay.⁴ Theoretically, they should be the same (Hartman et al. 1991, p. 142). However, Coursey et al. (1987) find that such disparities typically present for goods unfamiliar to consumers and that the willingness to accept measures converge to the willingness to pay results after repeated experiments.

This suggests that if the customers surveyed for the Victorian and New South Wales VCRs were largely unfamiliar with valuing reliability, the current measures might not be accurate, but that repeated surveys should improve the accuracy of the results.

Contingent valuation studies, including studies of electricity reliability, have also found a preference for the status quo (Hausman 1979; Hartman and Doane 1986). Hartman et al. (1991) found that in two groups of generally similar customers with very different historic levels of reliability, the majority in both groups preferred the levels of reliability that corresponded closely to their current level (p. 153). An important implication of this result, and an observation made by Energy Australia (2007), is that the number of complaints about quality of service is not a good indicator of whether an existing level of reliability is appropriate.

What are the implications?

In light of the above, some might question whether attempting to compute customer reliability values is worth the effort.

But the same dilemmas and complexities have been present in similar contingent valuation exercises for measuring natural resource damage (Diamond and Hausman 1994) and cost-benefit analyses of a wide range of public policies

⁴ Willingness to pay in this circumstance is the maximum that an individual would be willing to pay to reduce the number or frequency of power interruptions by a given amount. Willingness to accept is the minimum an individual would be willing to receive to accept an increase in duration or frequency of outages of the same amount.

(Whitehead and Blomquist 2006). The general, but tentative, view is that a number is better than no number (Whitehead and Blomquist 2006, p. 112).

The key point is that, estimated or not, for any given level of reliability, there is a corresponding value that customers place on it. At the very least, the valuation implicit in any mandated standard should be made explicit, and assessed for its reasonableness using empirical evidence. A claim that it is not possible to collect *any* evidence of the costs and benefits, would imply that reliability standards can be selected by throwing a dice—not a compelling approach.

Once the available evidence, explicit or otherwise, is assembled, it should first be tested for reasonableness, and then used to limit the range of possible reliability levels set by a government or regulator. If this is not done, there is the strong potential for reliability standards to be anchored to engineering, political or commercial preferences or prejudices, rather than customer preferences.

A role for the Australian Bureau of Statistics

Given the complexities of compiling robust estimates of VCRs, and the costs of basing reliability decisions on sub-standard estimates, the most appropriate body to carry out the ongoing research necessary to improve VCR measures for the NEM would most likely be the Australian Bureau of Statistics (ABS).

The ABS has the technical capabilities to recognise and deal with the methodological challenges of undertaking surveys to measure non-market goods. They also have the organisational capacity to collect and synthesise large datasets.

Their independence ensures that external concerns such as political or commercial considerations would not influence their estimates of VCR. Comparisons between VCRs and other ABS data covering income, education, occupation and household characteristics would lead to a better understanding of the drivers of VCRs (and therefore feed into better surveys) in the future.

It is appropriate, however, that the industry (and therefore electricity customers) fund the research undertaken by the ABS. AEMO should commission and pay the ABS to undertake regular and detailed surveys, disaggregated by customer type, throughout the NEM. It is likely that the ABS could combine these surveys with others that they are conducting periodically and in that way reduce the costs of the research. Having such survey evidence available would provide greater surety that the benefits to customers of investments to enhance network reliability exceeded the costs.

Other costs to be considered — the difficulty with transmission

The framework for determining an appropriate level of reliability is the same for transmission and distribution networks. However, given the different nature and consequences of faults, the methods used to discover customer valuations and the values themselves are likely to be different. Some transmission specific considerations include that:

- distribution businesses are also ‘customers’ for transmission businesses, and distribution networks can be damaged from voltage surges or other equipment failure in connected transmission lines
- interruptions in transmission networks can include wide-spread cascading interruptions that take a long time to resolve. The costs of these faults could be larger than the costs found in a distribution-focussed survey. For example, the options for customers facing an outage might be more limited and costly if the whole region is without power (for example, making it harder to rely on friends or family)
- transmission businesses have to consider high-cost, low-probability events, and how these might be valued by customers who may have never experienced such extensive outages before. Some costs might include having to truck in fuel for generators and fresh water from long distances, or the costs to society of being without everyday services such as street lighting and some public transport
- transmission networks in one part of the NEM are connected to transmission networks in other parts. Failures in one part of the network can have network-wide impacts. Any such costs would also need to be included.

Setting standards in a dynamic environment

Customer preferences for reliability do not remain constant. Nor do the technologies for, and costs of, improving reliability. For example, as electrical appliances become cheaper, and people become more reliant on them, the premium on reliability is likely to rise (chapter 10). Similarly, increasing peak demand, more extreme weather events or changing costs of key inputs such as labour are likely to increase the costs of improving reliability. Such changes will in turn have implications for the appropriate level of reliability, highlighting the need for regular re-assessments of VCRs and in intermediate periods, empirically justified extrapolation.

The problem with averages

Networks cannot supply electricity with different levels of reliability to houses that are next door to each other. Accordingly, efficient levels of reliability do not mean that every person or business will get their desired trade-off between reliability and price. There will be customers who have a much higher (lower) willingness to pay and who will want a higher (lower) level of reliability. People with higher values may be able, if there are cost-effective options, to achieve greater reliability through other means, such as backup generators. But people with lower than average values of reliability have little capacity to adjust down.

Equity considerations

Efficient reliability may not always mean equitable reliability. The degree to which equity concerns should affect regulatory reliability standards is complex and context dependent. In some cases, people may value reliability very highly, but be unable to pay for it given income constraints. For instance, someone on an oxygen machine for emphysema will require reliable power to survive. However, circumstances where the value is as high as this usually require 100 per cent reliability, best met through ancillary (transparently subsidised) measures, such as a battery backup, rather than by increasing the reliability of the entire network.

Extreme cases like this aside, the most likely source of tension between efficiency and equity would arise if people on lower income placed a low value on reliability, but had to pay a higher network contribution due to the weight of more affluent households assigning a higher value to reliability. There is some evidence of this, albeit mainly from the US. In a large-scale meta-study, lower income was associated with smaller values of lost load (Sullivan et al. 2009, p. 67). Moreover, the uptake of electrical goods is lower among lower-income people (for example, air conditioning, multiple refrigerators and pool pumps), which would tend to reduce their VCR.

Addressing such tensions might be possible through different pricing menus. For instance, people on lower incomes spending smaller amounts on power could be offered a reduced fixed charge (which would be the main funding source for the fixed costs associated with meeting reliability standards) and a higher usage charge. Alternatively, some sort of subsidy might be provided, though any such subsidies should be transparent, and funded efficiently (chapter 3). (Given that current levels of reliability appear to be in excess of people's average value of reliability — chapters 15 and 16 — were this to be corrected, electricity network charges should not rise as fast in the future, which would also assist lower income households.)

Of course, not all lower-income people will have relatively low VCRs. One example may be elderly people requiring reliable heating or cooling — with people aged above 65 years appearing to have (other things equal) higher VCRs than younger household customers (Sullivan et al. 2009, p. 67). However, it is unlikely that these older customers would be penalised by the sort of valuation approaches outlined above, given that there are many other non-vulnerable people who also value highly reliable systems.

The difficulty with the Back o' Bourke

A correctly estimated VCR will indicate the costs that customers experience due to power interruptions in different locations. But the costs to increase (or even maintain) levels of reliability to some places, especially in rural or remote locations, are likely to far outweigh the willingness (or ability) to pay of the customers who reside there.

Through an economic lens, prices should be cost reflective, and it can be difficult to justify maintaining network infrastructure to deliver relatively reliable supply to some locations at a price at reasonable parity with urban areas. VCRs for these areas then lose their explanatory power.

However, governments in the NEM have expressed a clear desire to ensure service delivery at reasonable reliability continues for all customers. As described by the MCE:

Energy supply is considered to be an essential service and vital to the maintenance of the standard of living of individuals and households. Governments are concerned to avoid the outcomes a loss of supply due to inability to pay [for] (or a refusal to supply) electricity ... can have on residential users (MCE n.d., p. 6).

The typical response has been some form of subsidy, sometimes effectively funded by other customers (and hidden) and sometimes by government. The latter is to be preferred, and any such Community Service Obligations should be transparent. Other responses to ensure that customers in rural and remote locations receive electricity supplied through networks connected into the NEM have included specific reliability standards (including Guaranteed Service Levels) and requirements to connect new customers.

The level of reliability that customers receive in these locations is therefore largely a question determined by governments. However, as well as being transparent and preferably funded directly by governments, the configuration of subsidies used to meet reliability objectives should create incentives for cost effective approaches. Energy supply to rural and remote areas can be provided in a number of ways, and

the options available will increase into the future. If cheaper options exist to supply reliable electricity to an area than maintaining network infrastructure, service obligations should encourage, not hinder, network businesses to uncover them.

14.6 Concluding comments

Overall, decisions about the reliability of electricity networks should be empirically based, drawing on survey evidence about the value that people and businesses place on the various dimensions of reliability. This would ensure better outcomes for consumers as a whole, and most likely generate larger relative benefits for poorer households. If governments wish to provide subsidies to particular groups, then they should indicate the rationale for doing so, the basis for eligibility, indicate the costs transparently, and use the most efficient funding sources.

Revealing the value that customers place on reliability is only one prerequisite for efficiency and needs to be weighed against the costs of achieving different reliability levels.

The aim of benchmarking reliability standards is to discover the optimal trade-off and to identify what aspects of the regulatory regime are allowing (if not encouraging) inefficient expenditure to occur.

The next two chapters explore reliability in transmission and distribution networks, and the regulation affecting reliability in each.

DRAFT FINDING 14.1

Efficient levels of reliability are based on balancing the benefits to customers of fewer interruptions with the costs to network businesses of building, maintaining and operating reliable networks. Identifying the point at which the costs to network businesses of further increments in reliability exceed the additional benefits for customers should be the first step in regulating reliability.

DRAFT FINDING 14.2

Current estimates of the value that customers place on reliability are based on inadequate sampling, data and methodology and need to be updated regularly.

The Australian Energy Market Operator should commission and pay the Australian Bureau of Statistics to undertake regular, detailed, disaggregated surveys based on best practice methodologies to reveal the value of reliability for different categories of customers, with the methodologies and results made public.

The Australian Energy Market Operator should commission suitably qualified experts to consider and measure the costs of interruptions not likely to be captured in the Australian Bureau of Statistics surveys. This should include the costs associated with citywide disruptions, including to telecommunications, water services and public transport, and the resulting loss of international reputation from lower reliability. The Australian Energy Market Operator should use these measures to supplement the results of the surveys.

15 Transmission reliability

Key points

- Reliability settings for transmission networks in the National Electricity Market (NEM) are important for network planning, operation and performance.
- Underinvestment in reliability can have large costs, especially if it leads to power outages that cause significant detriment to consumers
- Ensuring a network is reliable can also be costly to consumers, requiring investment in network augmentations, network maintenance and replacement, and other non-network solutions.
- Standards for reliability in the NEM differ markedly between jurisdictions although three main types of framework can be identified: one uses deterministic standards, one uses probabilistic planning and the third a combination of both.
- None of the three currently used frameworks for reliability settings in the NEM is efficient (using efficiency criteria covering investments, standards, administration and compliance, NEM-wide effects and auditing compliance). Efficiency assessments of all three identify important characteristics for a new national framework.
- The same criteria can be used to assess the models for a new national transmission reliability framework currently being debated within the industry.
- A NEM-wide transmission reliability framework (that explicitly sets reliability standards to maximise net benefits) should generate large efficiency benefits throughout the NEM.
- A framework designed to ensure reliability standards are efficient most likely would:
 - take a NEM-wide perspective and displace any existing jurisdictional requirements
 - use a probabilistic process (with appropriate values of customer reliability) as part of a cost-benefit analysis of augmentations for reliability purposes
 - have an independent, third party responsible for reliability settings, with enforced transparency requirements
 - be integrated with the incentives in the Service Target Performance Incentive Scheme for reliability performance
 - encourage planning, and operational and performance actions to meet reliability requirements cost effectively, including using dynamic ratings on equipment.
- An efficient transmission reliability framework could produce net present value savings in the realm of \$1 billion within a single regulatory period, but much more over the long-run.

15.1 Introduction

The majority of power interruptions that customers experience within the National Electricity Market (NEM) result from faults or failures in distribution networks.

In contrast, transmission networks typically deliver high levels of reliability — indeed, transmission networks are said to be ‘inherently reliable’ (AEMC 2011e, p. 2). Transmission reliability needs to be high due to the size and scale of transmission networks and, thus, the magnitude of the consequences if transmission networks were to fail for any significant period of time (box 15.1).

Reliability settings for transmission networks apply within the context of network planning, operation and performance (box 15.2). They determine the reliability of transmission networks in the short term (within an operational timeframe ranging from the instantaneous through to several months into the future) and in the longer term (within a planning timeframe ranging from a few months to several decades into the future). They also determine how transmission businesses respond once an interruption has occurred (through performance standards).

Reliability settings, which are currently primarily the responsibility of individual jurisdictions, are a major driver of the costs of investment in transmission networks (AEMC 2008a).¹ Thus, inefficiencies in reliability settings can lead to inefficiencies in transmission network investment.

Indeed, the interaction of jurisdiction-based reliability settings with incentive regulation was a matter of concern for some participants. For example, the Australian Energy Regulator (AER) was critical of reliability settings and, in particular, the:

... ambiguity inherent with deterministic reliability criteria, and the wide degree of scope this allows [transmission network service providers] to interpret and apply such standards ... [S]ignificant linkages exist between the standards and the regulatory processes used to set regulated revenues and to assess network performance. Poorly defined reliability requirements make it difficult for the AER to assess whether the capital expenditure proposals of [transmission network service providers] are genuinely required to meet reliability requirements. (AER in AEMC 2008a, pp. 14, 16)

Some have even called the capacity to use reliability standards as a basis for inefficient investment the ‘Trojan Horse’ strategy. Others, using less colourful analogies, have argued that:

¹ For example, the Australian Energy Regulator recently approved more than \$2 billion in capital expenditure for load driven augmentations and replacements in Powerlink’s latest revenue determination (2012-2017).

... divergent transmission standards across the NEM result in ... potential for undue influence and discretion for [transmission network service providers]. (The Group,² cited in AEMC 2008a, pp.)

Box 15.1 The significant costs of unreliable transmission networks

Some of the most significant blackouts worldwide have resulted from inadequate planning, maintenance or operation of transmission networks in response to one or several contingencies (Cepin 2011, p. 16). For example:

- A blackout in Italy and Switzerland (28 September 2003) which affected 56 million people for 48 hours was caused by the operational overloading of a transmission line in Switzerland on a hot day, causing the line to sag and arc to the trees below. Power flows on the inter-network connections between Italy and its neighbours were cut in response to the failed Swiss transmission line, causing the Italian power system to collapse.
- Moscow (25 May 2005) experienced a blackout estimated to have caused damage to the value of \$US 70 million as a result of the failure of two electrical transformers that were reported to be 'exhausted'. A combination of old and damaged transmission infrastructure and mistakes by operational personnel are said to have been the cause of the blackout.
- Severe outages in the United States and Canada (14 August 2003) that affected 260 power plants and tens of millions of people (some for up to eight days), and caused 61 800 MW of lost load, were caused by a combination of factors, including inadequate real time information available to network operators, failure to manage tree growth in easements, and a failure to manage network effects across interconnected regional networks.
- 10 million people across Germany, France, Belgium, Spain and Austria were without power on 4 November 2006 due to errors of a transmission system operator in Germany, inadequate system security procedures, lack of information relayed to system operators in connected networks, and inadequate redundancy in the networks.
- In late July 2012, India faced massive system failures that cut power to around 670 million people or around 10 per cent of the world's population (Yardley and Harris 2012).
- The economic cost of outages in some African countries amounted to around 6 per cent of their annual GDP (Foster and Briceno-Garmendia 2010).

This chapter focuses on reliability settings within transmission planning frameworks, since these have the greatest effect on overall transmission network reliability. Using a set of criteria, the chapter describes and assesses the efficiency of existing frameworks, and a recent model proposed by the Australian Energy Market Commission (AEMC). The chapter then draws conclusions about the desirable characteristics of a new framework for transmission reliability in the

² 'The Group' includes Loy Yang Management Company Pty Ltd, AGL Hydro Pty Ltd, International Power Australia, TRUenergy Pty Ltd and Flinders Power.

NEM. Operational and performance standards are addressed briefly towards the end of this chapter.

Box 15.2 Reliability settings in transmission networks

Each jurisdiction's reliability settings are a critical factor in transmission planning, operation and performance. Planning, operational and performance standards are designed to influence the likelihood, size and the duration of an outage.

Reliability of the network in the operational timeframe is largely controlled by network operators. The National Electricity Rules (schedules 5.1a and 5.1) specify that the network must remain in a secure operating state.³

Requirements for reliability beyond those specified in the Rules are mostly set at the jurisdictional level, except the NEM-wide standard that unserved energy per year for each region must not exceed 0.002 per cent of the total energy consumed for that year.

Transmission businesses also set standards for the proportion of line and transformer capacity that can be used at any given time. This can affect congestion on transmission lines and the order of dispatch of generation (chapter 18).

Post-interruption performance standards exist to prompt transmission businesses to respond quickly when an outage occurs. Some elements of performance are captured in standards set by jurisdictions, and performance is also part of the AER's Service Target Performance Incentive Scheme for transmission.

In the planning timeframe, jurisdictional planning standards aim to ensure that as demand changes, networks can continue to operate in a secure state given the contingency events that might arise.⁴

15.2 Frameworks for transmission reliability

Within the NEM, each jurisdiction has a separate planning framework for setting reliability standards for transmission businesses (table 15.1). The frameworks vary in the:

³ A secure operating state requires the power system to be in a satisfactory operating state and to be able to return to a satisfactory operating state following the occurrence of any credible contingency. A satisfactory operating state requires all network elements to be loaded within their ratings. AEMO considers contingencies to be credible if it is reasonably possible that they might occur (AEMO 2012e, p. 8).

⁴ A contingency event is an event affecting the power system that AEMO expects would be likely to involve the failure or removal from operational service of one or more generating units and/or transmission elements (The Rules, clause 4.2.3(a)).

- type of standards applied and the level of discretion businesses have when meeting them
- level of standards, both within jurisdictions where standards in central business district (CBD) areas are usually higher than elsewhere, and between jurisdictions even for similar types of location and customer
- body responsible for setting standards and the instruments used to specify them, including codes, licence conditions, legislation and Network Management Plans.

Table 15.1 Transmission network reliability standards under existing planning frameworks^a

<i>State</i>	<i>Type of standard</i>	<i>Standard</i>	<i>Source of standard</i>
NSW	Deterministic	N-1 everywhere, except CBD of Sydney where it is N-2	Contained in Transmission Network Design and Reliability Standard for NSW from the Department of Industry and Investment
Vic	Probabilistic planning	Standard depends on the value of customer reliability (VCR) used at each connection point. The higher the VCR, the higher the standard (Melbourne CBD has the highest VCR)	Sections 50C and 50F of the National Electricity Law
Qld	Deterministic	N-1 everywhere and includes generation assets (sometimes expressed as N-1-G)	Transmission Authority (licence) issued under S.34 of the Queensland Electricity Act 1994
SA	Expressed as deterministic, but changes are made based on probabilistic analysis	Six (soon to be five) categories of standard specified at connection points ranging from N to equivalent N-2 for line and transformer capacity. Categorisation depends on VCR at that point	Electricity Transmission Code administered by ESCOSA with advice from the Australian Energy Market Operator
Tas	Deterministic and performance based, according to limits on size of load interrupted or duration of interruption	For intact system: N-1 for connections >25 MW. No asset failure will interrupt >850 MW No credible contingency will cause unserved energy >3000 MWh For network element out of service, no credible contingency to cause unserved energy of >18 000 MWh	Regulations recommended by Tasmanian Reliability and Network Planning Panel of the Tasmanian Energy Regulator and issued by Tasmanian Government

^a Deterministic standards and probabilistic planning are described in boxes 15.4 and 15.6 respectively and VCRs are discussed in chapter 14.

Source: AEMC (2008a).

Each planning framework is a reflection of the historical development of the electricity network in the particular jurisdiction prior to the NEM. The final report of the COAG Independent Review of Energy Market Directions in 2002 noted that the Panel was ‘very much aware of community and hence government sensitivity to

issues of supply reliability’ (MCE 2002, p. 8), which underpinned the reluctance of jurisdictions to relinquish control of reliability settings in their networks.

While significant variations between jurisdictions exist, it is possible to assign each jurisdiction’s framework into one of three broad planning frameworks for setting transmission network reliability standards:

- the use of deterministic standards in New South Wales, Queensland and Tasmania
- probabilistic planning in Victoria
- the use of hybrid standards in South Australia.

There has also been considerable debate around a possible national framework for transmission reliability. The Final Report of the AEMC’s *Transmission Reliability Standards Review* found that most parties agreed with a national framework, but differed in how they envisioned that framework, and most particularly, its scope to allow jurisdictions to set their own standards (AEMC 2008a, p. 13). The debate currently revolves around two models for a national framework for transmission reliability and planning:

- an extension of Victoria’s probabilistic planning process to the rest of the NEM (referred to as the ‘AEMO planner model’)
- the AEMC’s preferred model.

As such, four broad frameworks either exist or are being considered in the NEM. The remainder of this section describes these frameworks and assesses the efficiency of levels of reliability that are determined within them.

Approach to assessing planning frameworks and reliability standards

The efficiency of reliability standards within transmission planning frameworks can be assessed in three main ways, including:

- how the frameworks influence the choices that transmission businesses make about the various options for meeting reliability standards
- whether the standards themselves are set using a methodology based on the value consumers place on reliability (chapter 14)
- how costly the frameworks are to administer and to comply with.

A comprehensive assessment also requires taking into account key characteristics of transmission networks (box 15.3).

Box 15.3 Characteristics of transmission networks in the NEM

There are three key characteristics of transmission networks that are important in a consideration of transmission network planning in the NEM.

First, from a consumer's and regulator's perspective, reliability in transmission networks is less easy to observe than in distribution networks. Transmission networks are planned so that, for the most part, interruptions are avoided. Reliability standards for transmission networks target indicators of the *likelihood* of interruptions. These can include redundancy in the network, the probabilities of contingencies occurring, and network availability.⁵

Second, the power flows in, and reliability of, a transmission network within any NEM region affects the entire NEM, so that a problem in one part of the network can surface some distance away. These 'network effects' mean that reliability standards need to consider the effect that changes to a network in one region can have on a network in another. This suggests that an assessment of the efficiency of standards must take account of the costs and benefits incurred throughout the NEM.

Third, and related to the above point, the meshed nature of parts of transmission networks and the interconnection of transmission networks in the NEM mean that failures in one part of a network can, if only rarely, 'cascade' into other interconnected networks, causing mass outages. Cascading failures can have high costs (potentially more than a transmission business could bear, or even insure for at a reasonable cost, if it were required to fully compensate customers).

These characteristics require that the efficiency of reliability frameworks is assessed with a NEM-wide perspective including by considering how well the frameworks:

- assist with the management of the national grid
- encourage neutrality in choices between intra- and inter-regional network and non-network solutions
- deal with network effects and the possibility of cascading failures through the NEM.

A further consideration is whether the frameworks incorporate auditing of facilities and processes in transmission networks to assess the latent and actual reliability of networks. The reliability of transmission networks is hard to observe using a set of key output measures of performance. Therefore the only way of assessing the inherent reliability of such networks is to both:

- specify in some way what needs to be done to achieve a given level of reliability

⁵ Availability is a measure of the share of time that all transmission assets are in use, (or available to be used). Planned and unplanned maintenance and upgrades take assets out of use and reduce availability.

-
- utilise methods to confirm that the transmission business is actually doing what it is supposed to have done.

In this sense, there is an analogy to safety management systems where a set of risk reduction measures are agreed, but then there is an auditing process to confirm that these are in place and operating as intended. Just as for major failures with a transmission network, it is not acceptable just to wait and see if a major safety problem eventually arises.

The broad planning frameworks in the NEM are therefore assessed in terms of the following five broad criteria:

- *efficiency in investments*
- *efficiency of standards*
- *minimising administrative and compliance burdens*
- *NEM wide effects*
- *auditing compliance to ensure reliability and efficiency in the long run.*

15.3 New South Wales, Queensland and Tasmania

Governance

The three state-owned transmission businesses in New South Wales, Queensland and Tasmania — Transgrid, Powerlink and Transend — must comply with planning standards specified in jurisdictional license conditions or under statute. In New South Wales, the Commission understands that the relevant minister set standards in 2005, with advice from Transgrid. In Queensland, standards are contained in Powerlink's Transmission Authority, issued by the relevant minister in 2004 under the *Electricity Act (1994)*. These standards were affirmed by the Somerville report into distribution reliability standards in 2004 (AEMC 2008a, p. 177). In Tasmania, planning standards were set in 2006, based on advice from the Tasmanian Reliability and Network Planning Panel to the Tasmanian regulator. The planning standards in the three States have not been reviewed formally since they were first established.

Failing to meet reliability standards in all three jurisdictions can result in penalties for the transmission businesses. At a maximum, a transmission business can have its licence revoked for breaching the conditions that it is obliged to meet. To date this has never occurred in the NEM.

Deterministic planning

Transgrid, Powerlink and Transend use deterministic standards as a basis for planning and augmenting the networks to ensure reliability. Deterministic standards build redundancy into the network so that when a contingency occurs, an interruption to power supply can either be reduced or totally avoided (box 15.4).

Box 15.4 Deterministic standards

Deterministic standards specify how much redundancy needs to be built into a network. Standards are expressed using 'N-x' notation, where N refers to the number of elements in a part of the network and x is the number of elements that can fail at the same time without causing an interruption to power supply. For example, a network built to a strict N-1 standard will be able to supply peak load with one element not operating, even if it is the largest element in the network.

For example, in year one, a line in a network has a maximum demand of 800 MW. For this part of the network to be rated at N-1 in year one, two 800 MW lines are required so that if a fault occurs on one, the other line can carry the uninterrupted load. However, demand forecasts predict that by year five, maximum demand will increase to 850 MW. Screening studies by the network business reveal that the growth in maximum demand to 850 MW will mean that the network will no longer meet an N-1 criterion in year five. To meet the criterion, a third line would need to be built on the network, or demand would need to be supplied from another line or reduced (through demand management).

Deterministic standards are referred to as redundancy standards because for most of the time, the extra capacity is not used. If a third line were built in the example above, it would only be used at critical peak demand (which occurs around 40 hours per year (chapter 9)) and only if a contingency occurred on one of the existing lines.

Electricity network businesses generally have different deterministic standards for different parts of their networks. For example, in New South Wales, sub-transmission lines and the CBD of Sydney must be built to an N-2 standard. Urban and non-urban loads above 10 MVA⁶ must be reliable to N-1, and smaller loads to N-0.

Strict deterministic standards of N-1 or greater require that networks continue to operate without interrupting supply when one or more pieces of equipment fail, including at times of peak demand. For example, a line with an average demand of 200 MW and a peak demand of 400 MW must have additional lines of at least 400 MW capacity in total in order to meet an N-1 standard.

⁶ On average a line with a capacity of 10 MVA would service less than around 4000 customers. This means that all transmission lines, except very small ones, have N-1 redundancy.

The application of deterministic standards by Transend in Tasmania is an example of a more flexible approach to redundancy planning, in which standards are allowed to be breached for short periods. This recognises that the likelihood that peak demand coincides with a contingency is small. In the example above, this might mean that if peak demand rises to 450 MW, the system will breach the N-1 criteria, but only for around 40 hours a year (chapter 9). If a contingency occurs at these times, the remaining equipment can usually carry extra load, at least for a short period until the problem is fixed or load shedding can be minimised.

Transmission networks link to distribution networks at connection points.⁷ At each connection point, distribution businesses provide the transmission business with a demand forecast for the customers connected to each point (box 15.5). The transmission businesses then run these demand forecasts through screening studies to identify parts of the network ('identified limitations') that might not meet standards as maximum demand increases.

Box 15.5 Demand forecasts for transmission planning

Transmission businesses use demand forecasts for each connection point (based on information from distribution businesses) when making their planning decisions. Transmission businesses also aggregate these connection point forecasts to publish a region-wide forecast in their Annual Planning Report. Transmission businesses produce these region-wide forecasts for New South Wales, Queensland and Tasmania. The Australian Energy Market Operator (AEMO) produces the forecasts for Victoria and South Australia.

Concerns have been raised about the incentive that transmission businesses might have to 'overstate demand and therefore over-invest' (AEMC 2011f, p. 144).

While maximum demand has often not reached the levels predicted in the forecasts — for example, AEMO found that the actual maximum demands were significantly lower than those forecast by the transmission business for Queensland over a period of five years (AEMO 2011c, p. 10) — this is not necessarily evidence of deliberate over-forecasting of demand.

However, in 2012, and in response to such discrepancies, AEMO began to release independent region-wide demand forecasts for New South Wales, Queensland and Tasmania (as well as a NEM-wide forecast). The AEMC has recently proposed that AEMO should be responsible for informing the demand forecasts used by transmission businesses for planning in the future (AEMC 2012f, p. v).

⁷ A connection point is where the transmission network transfers electricity to either a distribution network or a directly-connected large customer.

When the business identifies network limitations, all options are examined for meeting reliability standards into the future. These options might include augmentation of the network, demand management projects, or re-routing the flows through the network to remove some of the pressure on the constrained elements.

Once they have identified their preferred options, Transgrid, Powerlink and Transend include the forecast costs and a brief outline of these options in their revenue proposals to the AER every five years. Because augmentations can take several years to build, the transmission businesses will typically include proposed expenditure in their revenue proposals for projects to address risks to reliability that are not predicted to emerge up until six or seven years into the future.

The AER is responsible for determining whether the expenditure required and the options identified by the businesses are efficient. This exercise requires industry expertise and a detailed knowledge of the likely costs of different options, while also keeping in mind the incentives transmission businesses might have to over or under invest or prefer a particular type of option (chapter 5).

Shortly before commencing a project (with a value greater than \$5 million), the transmission business has to undertake a Regulatory Investment Test for Transmission (RIT-T) (chapter 19). This process introduces some transparency and requires that the business canvass several different options for addressing a network constraint. However, according to the AER:

... the framework, and particularly the RIT-T, may not result in beneficial investment occurring ... [and] current arrangements for network development would not deliver sufficient new augmentations between regions. There are concerns that the existing arrangements may promote reliability-driven region-centric transmission investment and create incentives on transmission businesses to build rather than explore alternatives. (sub. 13, pp. 26, 28)

It is not apparent that the RIT-T imposes significant constraint on the choices businesses make regarding options or their costs. While the RIT-T has to be submitted to the AER, which confirms that it has been carried out according to the specified process, by this stage the AER have already approved the capital forecast of the transmission business. Despite the word ‘Regulatory’ being included in the name of the RIT-T, this part of the process does not seem to have much, if any, regulatory ‘force’. Chapter 19 discusses this issue in more detail.

Assessment of efficiency

Using the five criteria set out above, the framework for transmission reliability applied in New South Wales, Queensland and Tasmania can be assessed for possible areas of inefficiency.

Efficiency of investments

It appears that the incentive to identify and install the cheapest solution to address an identified network constraint is low:

- deterministic standards create a bias towards network investment solutions. Businesses with strict deterministic standards have a strong incentive to build redundancy into the network to meet standards, rather than identify more innovative solutions, including non-network solutions
- the level and nature of scrutiny applied to the options presented in the RIT-T is probably insufficient to be a motivator for the businesses to identify the most efficient option
- the profit motivation for state-owned enterprises as a driver of behaviour appears to be low (chapter 5). State owned enterprises might also have objectives other than to maximise profits (chapter 7).

The bias towards network solutions to meet deterministic standards is possibly exacerbated by the potential adverse consequences for Powerlink, Transgrid and Transend of not meeting their standards. Consequences can range from a business losing their licence at one extreme, to being required to report to the Minister about the reasons for missing the standard, and outlining a strategy to rectify the situation, at the other. Regardless, any significant outage can have substantial political and reputational effects for network businesses and government, even if no formal penalty is applied. The AEMC noted that:

... jurisdictional reliability standards reflect the political reality that if the lights go out in a jurisdiction, it is the government of the jurisdiction that faces the economic and political consequences and manages the public safety issues arising from a blackout. (AEMC 2008a, p. 168)

The greater the penalty — political, reputational or pecuniary — the greater is the likelihood that network businesses will augment their networks to increase reliability and seek to meet their standards within their own networks (that is, there will be a bias towards intra-regional investments). State-ownership of network businesses in New South Wales, Queensland and Tasmania is likely to increase political intervention arising from network failures, also contributing to the

tendency for excessive and inefficient network expenditure (one reason the Commission has recommended privatisation).

Efficiency of standards

It is unlikely that reliability standards in New South Wales, Queensland and Tasmania are efficient. This assessment is based less on the levels at which they are set, and more on the failure of the frameworks in which the standards are set to properly incorporate the value of customer reliability (chapter 14).

- The standards are not subject to cost-benefit analysis and do not consider customers' willingness to pay for the levels of reliability the standards support. In New South Wales, there have been calls for the government to:
... satisfy itself that ... current standards for network reliability and security align with customers' willingness to pay and take steps to ensure that future changes to standards are subject to rigorous cost-benefit analysis. (IPART 2011, p. 14)
- The standards have not changed for at least six years. Given that the efficient level of reliability is a dynamic concept, depending on shifting demand patterns, customer preferences and business costs, it is unlikely that a static set of standards would remain efficient over time.
- It is not clear that the Queensland, New South Wales or Tasmanian state governments have invested in the resources or expertise necessary to set efficient reliability standards for an electricity network business. This is a highly technical and specialist area and there is a likely bias by state governments to err on the side of wanting to avoid the political fallout from power outages without being able to assess the cost implications of their decisions or review the degree to which these accord with the willingness of customers to pay for these reliability standards. There may also be a conflict of interest (real or perceived) when governments set standards for state owned businesses that influence investments, and the subsequent dividends flow back to the governments (chapter 5).

Minimising administrative and compliance burdens

Third, and in contrast to the two previous concerns, the administrative and compliance burdens of the frameworks for transmission reliability in New South Wales, Queensland and Tasmania are likely to be low. This reflects that there is no need for comprehensive research into customer preferences as an input into standard setting processes, and the long length of time that standards have remained unchanged. For businesses, the compliance burden appears to be low with businesses dealing directly with the organisation setting the standards and monitoring compliance.

Neither the fourth nor fifth criteria (*NEM-wide effects* and *Auditing compliance to ensure reliability and efficiency in the long run*) are addressed by this type of planning framework.

15.4 Victoria and the Australian Energy Market Operator's preferred national model

The Australian Energy Market Operator's role as planner and procurer

Victoria's planning framework differs considerably from all other regions in the NEM. The Australian Energy Market Operator (AEMO) is responsible for planning and directing augmentations to the Victorian network and, it plans and procures services to achieve this (AEMO 2012e). As such, the Victorian transmission business, SP AusNet, does not receive revenue for capital expenditure for augmentations through the AER revenue determination process (AER 2008c, p. 44). SP AusNet, in consultation with AEMO, has responsibility for replacement of assets, maintaining assets and responding when a failure occurs.

SP AusNet is responsible for ensuring that reliability in the transmission network in Victoria is maintained, subject to the planning decisions made by AEMO. If a planning decision were found to be the cause of significant damage to a third party, AEMO could be liable if it had been negligent in carrying out its statutory planning functions.

AEMO's objective as a planner in Victoria is to ensure that the transmission network allows it to operate the system within security and system performance obligations, set out in schedules 5.1a and 5.1 of the National Electricity Rules (the 'Rules'). In doing this, AEMO's objective is to ensure the network minimises the total delivered cost of electricity to consumers over the long term by basing investment decisions on cost-benefit analysis.⁸ AEMO's planning documents indicate that its objective is to augment the transmission network only when the economic benefits from avoiding interruptions to power supply or congestion, equal or exceed the costs of implementing the augmentation (AEMO 2011c, p. 4).

AEMO publishes the Victorian Annual Planning Report, which assesses the ability of the network to supply forecast demand under a range of supply and demand scenarios:

- in the next five years at each connection point

⁸ As set out in s. 50F of the National Electricity Law.

-
- across the network in the longer term.

The Victorian distribution businesses jointly publish the Transmission Connection Planning Report that focusses on emerging constraints at each connection point for the next 10 years, using connection point specific demand forecasts. AEMO scales these connection point forecasts to be consistent with the state-wide medium energy growth scenario (AEMO 2012e, p. 7).

Probabilistic cost-benefit analysis

AEMO identifies emerging network limitations by running screening studies that test whether the network can be operated in a satisfactory state (or returned to a satisfactory state within 30 minutes after a contingency) under future possible demand and generation scenarios. To do this, AEMO uses deterministic descriptors to assess which parts of the network would not be in a satisfactory state under system normal conditions (N), after one contingency (N-1) and after a contingency when one element of the network is already not operating (N-1-1). These are similar to the screening studies that Powerlink, Transend and Transgrid undertake.

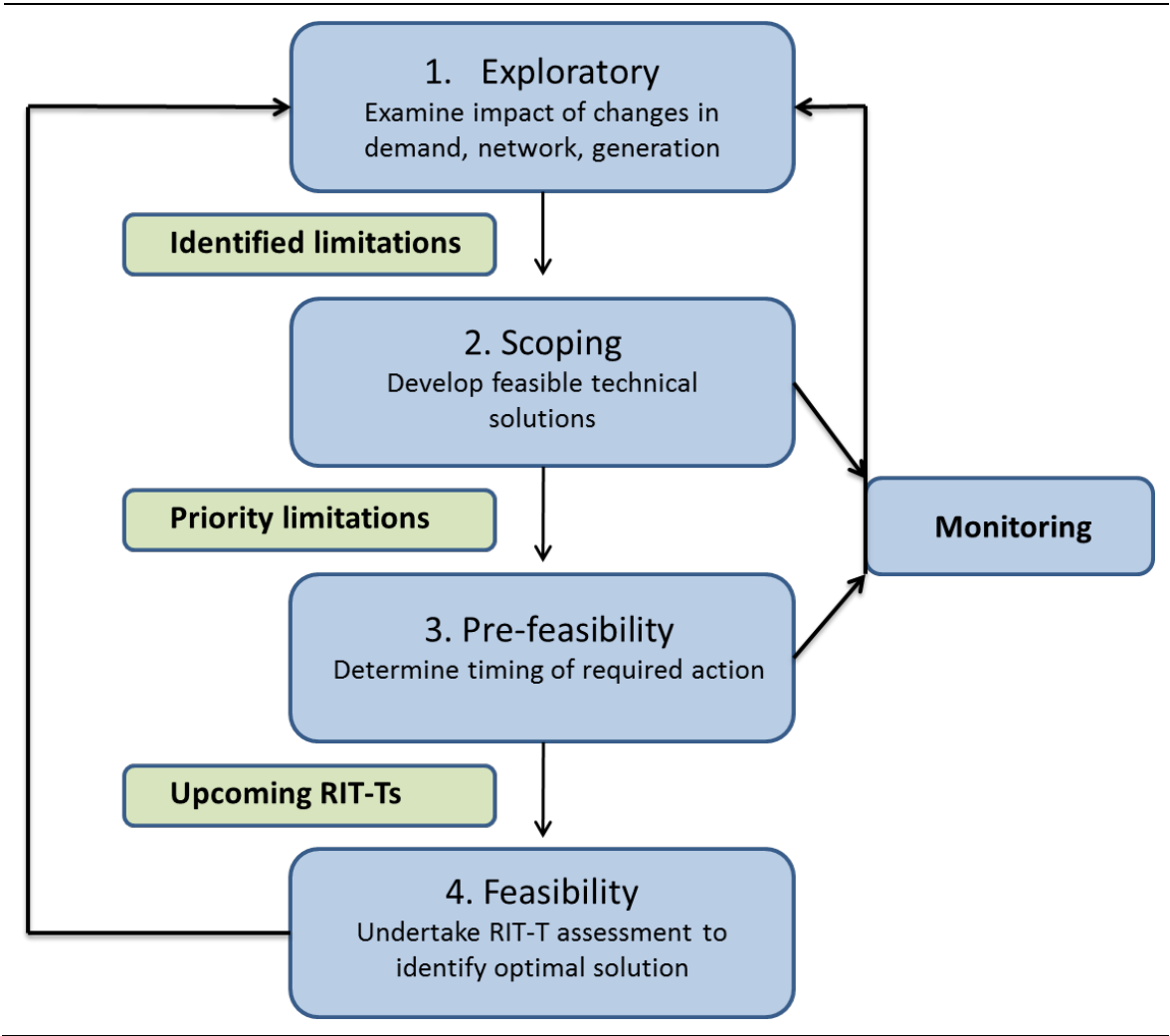
Once AEMO identifies an emerging constraint in the network (the exploratory phase in figure 15.1), it develops possible (investment and non-investment) options to remove those constraints, taking into account the long-term plans of distribution businesses and SP AusNet's replacement and refurbishment plans. Preliminary cost estimates and likely lead times are estimated for each option. AEMO assesses the costs and benefits of any substantial expenditure proposal before it is implemented. It considers the probabilities of contingencies and their resultant impacts on consumers, and sets them against the business costs of various options to address these impacts (box 15.6). The option with the greatest expected net benefit is usually the preferred option.

As costs and benefits change over time as demand changes, AEMO conducts pre-feasibility studies to assess whether augmentations might have future net benefits (figure 15.1).⁹ Optimal solutions and their timings are identified and costed in more

⁹ The Commission understands that the process outlined in box 15.6 is undertaken in some form in each stage of AEMO's planning process outlined in figure 15.1.

detail during feasibility studies conducted as part of the RIT-T process. This is a form of a ‘real options’ approach to planning.¹⁰

Figure 15.1 **Australian Energy Market Operator’s annual planning cycle in Victoria**



Data source: AEMO (2012e, p. 5).

¹⁰ A real options approach in the context of transmission planning allows investment decisions for reliability, once a potential constraint has been identified, to be delayed past the start of the regulatory period until the time that they are needed. The benefits of this approach are twofold. Firstly, if predictions about the level of reliability that customers value turn out to be incorrect, the required investment path can be altered. For example, if the value of customer reliability changes because an industrial estate closes down, the level of reliability that the remaining customers desire would fall. The second benefit arises from being able to take advantage of technology improvements or changing financial conditions or other network augmentations built in neighbouring regions. Delaying the decision about exactly what to build and how much it will cost until closer to the time of the project starting, allows the most recent developments to be taken into account.

Box 15.6 Australian Energy Market Operator's probabilistic cost-benefit analysis

Once a limitation in the network has been identified during the screening studies (which use deterministic indicators), AEMO applies a probabilistic planning approach to reliability that consists of the following four steps.

1. *Market analysis* involves designing many possible future scenarios using demand and generation forecasts. AEMO uses hour-by-hour spatial demand forecasts for different possible future peak demands, and hour-by-hour generation dispatch data to create demand and generation scenarios, while also taking into account the different likelihoods of exceeding the forecasts. (10 per cent and 50 per cent likelihoods are usually used.)
2. *Network analysis* establishes whether the scenarios threaten the stability of the system in terms of voltages, power flows and equipment ratings.
3. *System operation analysis* assesses the operational actions required under different scenarios in different conditions. Operational actions only occur if the system is not in a satisfactory operating state.¹¹ Operational actions can include network switching, generation re-dispatch and load shedding. These actions have costs, including interrupting customers' power when load shedding occurs or dispatching higher cost generators, making power more expensive. The analysis then examines what, if any, operational actions are required if a contingency occurs. Sometimes, analysis is required for four consecutive contingencies to ensure the network returns to a secure operating state.¹² Contingency data, and their likelihood of occurring, are compiled using historical outage data from the Victorian network.
4. The *most likely action value* is calculated by multiplying the probabilities of the scenarios and the contingencies by the costs of the operational actions that would be required in each situation and summing them together.

These four steps estimate the cost of a 'do nothing' scenario.

Steps 2 to 4 are repeated for each of the possible solutions to network constraints (such as augmentations or demand management) and compared with the 'do nothing' scenario. An option passes a cost-benefit test if it produces benefits above the do-nothing strategy sufficient to exceed the costs.

Sources: AEMO (2012e, pers. comm. 10 August 2012); VENCORP (2007).

¹¹ A satisfactory operating state requires all network elements to be loaded within their ratings (as defined in chapter 4 of the Rules) (AEMO 2012e, p. xx).

¹² A secure operating state is defined in footnote three.

When options to address emerging reliability concerns are separable¹³ from the rest of the network and are likely to cost at least \$10 million, AEMO calls for tenders for the construction, ownership and maintenance of the augmentation or non-network solution. AEMO specifies the limitation in the network, but not the preferred option it has previously identified. This is to ensure that there is opportunity for parties to submit other, possibly more innovative, options. It allows parts of the network to be contestable, with the advantages that competition brings to incentives for cost minimisation and innovation.

To date, 15 separable projects have gone to tender in Victoria (of which the incumbent transmission business, SP AusNet, has been awarded 13). The outcomes of these tenders are currently commercial in confidence and are not communicated to the AER, and the expenditure is therefore not incorporated in the regulated asset base at the start of the next regulatory period.

When options are not separable, AEMO negotiates with SP AusNet to carry out the development or project. SP AusNet receives revenue for the capital expenditure¹⁴ and operating costs for projects that are embedded in their network or for projects that they have won through the tender process. For non-separable projects, the revenue that SP AusNet receives is rolled into the regulated asset base at the end of the five year regulatory period, and is therefore available for any benchmarking exercises undertaken by the AER.

Assessment of efficiency

Efficiency of investments

The Victorian transmission planning framework appears to support efficient options for meeting reliability constraints. The decisions about what, where and when to build are made by AEMO, or are subject to competitive forces through tendering. AEMO, an expert, independent, not-for-profit planner, has little incentive to make

¹³ A separable project is one that can readily be identified as distinct from the rest of the network. Further, while it will require connection to the broader network, to be categorised as ‘separable’, a project must not materially interfere with the incumbent transmission business’s ability to run existing infrastructure.

¹⁴ The revenue is approved by AEMO by changing SP AusNet’s Transmission Use of System (referred to as TUOS) charges. In effect, this allows the business to collect more revenue from customers.

inefficient investment decisions¹⁵ and all investments must pass a cost-benefit test, the last iteration of which is delivered through the RIT-T process.¹⁶

AEMO also has no reason to prefer network or non-network solutions since it is not influenced by the need to meet deterministic standards. As a result, it can identify the most efficient option, which may be a network or non-network option, or a combination of both.

A further benefit arises from the probabilistic process identifying the most efficient timing of investments. Indeed, in some cases, the difference in outcomes between probabilistic planning and deterministic standards might be one of timing rather than the type or scope of project (Grid Australia, sub. 44).

AEMO's real options approach, however, has benefits. It outlines a stream of augmentations, each planned to commence at different points in the future according to demand forecasts, and assesses the economic case for each investment as its time for construction approaches, allowing changes in customer values and in relevant costs to be incorporated. The New Zealand Electricity Commission found that adopting a real options approach could result in savings of up to 30 per cent compared with orthodox investment planning methods (Electricity Commission 2006).

The Victorian Department of Primary Industries (DPI) has also argued for a 'dynamic probabilistic approach' in their submission to the Transmission Frameworks Review:

DPI considers that a dynamic probabilistic planning approach applied to transmission augmentations is likely to result in more accurate and efficient investment outcomes when compared to the setting of deterministic standards that are applied for a fixed period and which are based on analysis which is likely to become out of date over time as market events evolve. (DPI 2012b, p. 6)

The probabilistic planning undertaken by AEMO, through the use of repeated feasibility studies, incorporates a real options approach and ensures that investments

¹⁵ It is possible that AEMO has an incentive to 'make life easier' as the operator by making inefficient investment decisions, however, there does not appear to be evidence to support this conjecture. It is also possible that synergies exist between planning and operating the network, which AEMO can exploit when it carries out both roles.

¹⁶ One in-principle concern is whether the separation of planning functions from ownership, operation and maintenance could forgo the benefits of trade-offs between capex and opex in delivering reliability in the network. However, this problem is unlikely to be significant since AEMO considers a range of solutions as part of its cost-benefit probabilistic test for any investment and has ongoing consultations with the transmission business (which could raise such alternative solutions).

for reliability purposes are not undertaken when the costs (as negotiated between AEMO and the business, or revealed through competitive tender) outweigh the benefits. AEMO only procures or negotiates the investments at the time the projects are due to commence, and customers pay a cost that is equivalent to an informed purchaser in a workably competitive market. In contrast to the situation in New South Wales, Queensland and Tasmania, the cost-benefit analysis in Victoria is conducted and all options explored before approval for the revenue attributable to this capital spend occurs. Box 15.7 discusses the current role and application of the RIT-T in Victoria and elsewhere in the NEM.

The most commonly cited criticism of this model is that investments for non-separable projects are not decided by a business motivated by a profit incentive. However, this is either not much of a disadvantage, or may indeed have benefits in circumstances where the profit incentives of businesses are weak, or investment decisions are based on objectives other than profit (chapter 5 and 7) or when the experience of planning across the NEM gives AEMO increased exposure to new and innovative ways to address network constraints.

Costs of non-separable projects are negotiated between the business and AEMO, which then approves the required revenue for the business. This process should reveal reasonably efficient costs, provided AEMO is an informed party at the negotiations, and the transmission business does not attempt to inflate its cost estimates as an ‘ambit’ for negotiation. However, it is not necessarily transparent. In Victoria, either party can seek arbitration from the AER if negotiations fail to deliver an agreed cost for a project (although to date this has never occurred).

Efficiency of standards

The efficiency of standards in this model is more difficult to assess because probabilistic planning does not use ‘standards’. However, this criterion is concerned with whether the delivered levels of reliability (either through the use of and compliance with standards or through probabilistic planning) are aligned to the preferences of customers.

So long as the data and variables used in the analysis are accurate, probabilistic planning, as a form of cost-benefit analysis should align levels of reliability with customer preferences, taking account of temporary ‘mismatches’ due to the lumpiness of transmission assets. (Box 15.8 explains the difference between probabilistic and deterministic approaches to planning.)

Box 15.7 The role and application of the RIT-T

The Regulatory Investment Test for Transmission (the Test), as currently designed, has a narrow focus and is not equivalent to the cost-benefit analysis that AEMO carries out in the lead up to a network augmentation in Victoria. Outside Victoria, as discussed in chapter 19, the Test falls short of a comprehensive cost-benefit analysis for a number of reasons:

- benefits do not have to outweigh costs for a project to 'pass' the Test if the augmentation is being built for reliability purposes
- the transmission business intending to undertake a project carries out the Test — not an independent party
- the details of alternatives canvassed in the Test (and their costs and benefits) therefore cannot be rigorously tested by parties outside the business due to the information asymmetries that exist between the business and all others (except perhaps where AEMO is involved in an inter-regional project).
- other parts of the regulatory regime, as well as state ownership, can create incentives that cause businesses to prefer options that diverge from a true NEM-wide efficient solution. Given the above, these incentives will not be overcome by any requirements in the Test.

The Test also has little role in the AER's revenue determination process for transmission. The only role of any RIT-T in the revenue determination process is that the business must include any augmentation option that has passed a RIT-T in its aggregate capex revenue proposal. (In fact, many capital spending projects do not require a RIT-T and a RIT-T may not have been undertaken at the time the AER makes its revenue determination.) The AER does not approve specific investment projects, but instead provides a revenue allowance that leaves the business with choices about the timing and nature of its overall portfolio of investments (or other strategies required to meet reliability standards) over the regulatory period. Under that approach, the business must build to meet any specified standards, but if it can undertake the projects to achieve those standards at lower cost, it can retain the savings as profits. In that sense, the term 'Regulatory' Investment Test is a misnomer as it may have very little bearing on the aggregate capex revenue proposal and may make little difference to what would have been built had the Test not been present.

This is not to say that the present Test has no impact or should be discarded. The information asymmetries mentioned above are not so great that the Test is unable to shed light on the most egregious examples of gold plating, preference for network-based solutions, or intra-jurisdictional preference. Further, it does provide a platform for public consultation of possible alternative options, especially for demand management options.

The 'RIT-T' as undertaken by AEMO has a different role, more in keeping with the actual name of the Test. It is an independent cost-benefit analysis and actually determines the nature of the solution (which might not be capex) and the revenue to meet those costs. To have the RIT-T play the same role in other jurisdictions, the AER or some other body could use an objectively appraised RIT-T to determine required investments, but to do so effectively would require impartial advice on specifications, timing, costs and network-wide needs.

Box 15.8 Probabilistic and deterministic planning

A framework that delivers efficient levels of reliability can *describe* the network and the reliability outcomes in a number of ways: deterministically; using probabilities of interruptions; using maximum interruption durations or occurrence; or using values of lost load.

Across the jurisdictions in the NEM, there are fewer differences in the way levels of reliability are described than there are how they are set, and what party sets them. For example, Victoria's probabilistic framework uses deterministic N-1 indicators for its initial screening of the network. South Australia's hybrid standards are an example of moving from a probabilistic analysis to deterministic criteria. Augmentations of the Victorian network under a probabilistic framework can be converted into a description of the level of redundancy using deterministic terminology. AEMO also converts the NEM-wide 0.002 per cent unserved energy reliability standard into deterministic standards to identify the level of reserve in each NEM region (AEMC 2007a, p. 30).

However, *identifying* an efficient level of reliability must incorporate probabilistic analysis. The behaviour of electricity networks is stochastic in nature and therefore system planning should use probabilistic techniques. In contrast, 'deterministic approaches ... do not and cannot recognise the probabilistic or stochastic nature of system behaviour, of customer demands, or of component failures' (Zhang et al. 2009, p. 121). This is also recognised by Billinton and Allan (1996), who said that:

... there is no need to constrain artificially the inherent probabilistic or stochastic nature of a power system into a deterministic domain despite the fact that such a domain may feel more comfortable and secure. (p. 4)

AEMO's probabilistic planning might not always be best practice, and neither do all deterministic standards necessarily result in inefficient reliability levels. Joskow and Tirole (2007) asserted that

... there continues to be a lack of adequate communication and understanding between economists focused on the design and evaluation of alternative market mechanisms and network engineers focused on the physical complexities of electric power networks and the constraints that these physical requirements may place on market mechanisms. (p. 61)

Some form of probabilistic planning can reconcile these two agendas. Whether the required communication between economists and network engineers requires translating probabilistic outcomes at the time of investment into deterministic descriptors should be a secondary consideration.

Sources: AEMC (2007a); Billinton and Allan (1996); Joskow and Tirole (2007); Zhang et al. (2009).

However, there are several concerns about the extent to which AEMO's probabilistic process currently delivers efficient levels of reliability.

First, there are some concerns about the quality of the modelling, parameters and data.

- Some low probability catastrophic events are difficult to model because there is insufficient historical data to determine the probabilities. This complexity increases where a set of interdependent effects may lead to catastrophic failure. For example, a hot day may lead to the coincidence of peak demand, a failure of a transmission line due to arcing, inadequate water to feed hydro generators (if the hot day coincides with a prolonged drought), fires that take out interconnectors, and shortages of maintenance crew at parts of the network that need repair. Given their possible lack of independence, the probability of such events cannot be calculated as the multiple of the probabilities of the events occurring separately (which has apparently been AEMO's approach). Ignoring dependence would underestimate the true likelihood of catastrophic failure. However, AEMO has begun to incorporate hypothetical high impact, low probability events in its planning, rather than only accounting for events captured in the historical data.
- There are uncertainties about the quality of the data (and the methods) used to estimate the value of customer reliability (chapter 14). It is crucial to take account of all the costs imposed on customers from operational actions (such as load shedding or dispatching more costly generators) when making efficient investment decisions, even if the costs are difficult to measure. If nothing else, a range of VCRs should be used in modelling.

Second, some participants in this inquiry have described the planning approach used by AEMO as a 'black box' because the process is not transparent or easy to replicate. Some stakeholders have also raised concerns about the lack of scrutiny of AEMO's planning decisions and the difficulty external parties might have in testing them.¹⁷

These are legitimate concerns. Introducing mandatory reporting to the AER and making all processes transparent, would make testing the efficiency of AEMO's planning decisions easier and would ensure that decisions are made as a result of robust cost-benefit analysis. It appears that AEMO has partly recognised the issue, and has recently publicly released more documentation about its planning process, including its database of scenarios and contingencies.

¹⁷ One indirect test is whether the values of customer reliability *revealed* from augmentations made in Victoria are reasonably consistent with the measured survey values of customer reliability.

Minimising administrative and compliance burdens

The complexity of AEMO's planning process and analysis suggests that it is likely to be more costly than the equivalent in New South Wales, Queensland and Tasmania. While the software required is similar to that used in other states, the additional costs arise from the labour costs to run the simulations; the compilation and upkeep of the required datasets including identifying the probabilities of different contingencies; and the design of the scenarios. The separation of functions between AEMO and SP AusNet also makes constant communication between the organisations a necessity.

For SP AusNet, and other competing businesses, tendering for a separable project can also be costly. These costs are discussed in more detail in section 15.8.

NEM-wide effects

While the jurisdiction-based focus of the planning in this framework currently rules out explicit consideration of NEM-wide efficiencies, AEMO's joint role as Victorian planner and operator of the NEM suggests that network effects are likely to be considered. The probabilistic nature of the planning can also more easily integrate inter-regional solutions.

In considering the extension of this model to the rest of the NEM, incorporating detailed representation of the entire NEM in the model/s that AEMO uses in its probabilistic planning would effectively *take account of NEM-wide effects*. AEMO would concurrently therefore become responsible for the national grid.

Auditing compliance to ensure reliability and efficiency in the long run

As far as the Commission is aware, AEMO does not carry out independent auditing of facilities or processes in SP AusNet's network.

15.5 South Australia

Governance

Transmission planning and operation in South Australia is set out in the Electricity Transmission Code, which is administered by the Essential Services Commission of South Australia (ESCOSA).

AEMO plays an important advisory role for planning standards in South Australia.¹⁸ It regularly (and publicly) reports on the state of the network and provides advice on the planning and maintenance of transmission equipment in South Australia. AEMO's advice is wide ranging and includes advice on the setting of reliability standards in South Australia and the appropriate capital expenditure required to meet them for each revenue determination period. (AEMO does not advise on replacement or operating expenditure.) The advice AEMO issues to ESCOSA and ElectraNet is not binding. However, the Commission understands that the AER takes account of AEMO's capital expenditure recommendations to ElectraNet.

Hybrid reliability standards

The Electricity Transmission Code sets out the requirements for transmission networks and services in South Australia, including planning standards for the network and connection points. The planning standards are specified deterministically according to six categories of redundancy (which will reduce to five categories from 2013). Each connection point is categorised into one of the six levels of redundancy (ESCOSA 2012). Originally, the categories were determined by assessing the redundancy that existed in the network in the 12 months prior to the establishment of the Electricity Transmission Code in 1999. The intention was that customers would not experience a reduction in reliability after network privatisation.

Every five years, the categorisation of each connection point is reviewed by AEMO at the request of the South Australian Government. The review process uses a probabilistic framework to assess whether changes in the forecast maximum demand at a connection point warrant its reclassification to a higher, but not lower, category of redundancy.

This assessment is made by carrying out a probabilistic analysis of the network, and specifically the connection point, to determine whether the expected costs of interruptions (calculated by multiplying the probability of interruptions occurring by the costs incurred by customers from interruptions) are larger than the cost of reducing the probability of interruptions occurring by investing in the network. If the expected costs to customers are very large (which would most likely be due to increases in demand and therefore larger effects of an interruption at the connection point) several investment options might be justified. If this is the case, the ensuing

¹⁸ Underpinned by provisions in the National Electricity Law (Division 2, Subdivision 2, section 50B).

redundancy in the network as a result of the new investments would correspond to a higher reliability category for that connection point. Connection points cannot currently be reclassified to a lower category.

The probabilities of contingencies used in this analysis are derived from historical observations in South Australia and are supplied by ElectraNet. If AEMO identifies potentially costly constraints, then it assesses the benefits of addressing these against their costs. However, unlike in Victoria, AEMO does not undertake an independent assessment of possible upgrade options and their costs, including demand management options, but must use the cost estimates of the augmentations specified and determined by ElectraNet.

Assessment of efficiency

Efficiency of investments

The hybrid model is likely to be more efficient than current arrangements in New South Wales, Queensland and Tasmania because the deterministic standards at least initially reflect probabilistic modelling, and because the views of AEMO are factored into the AER's revenue determinations.¹⁹ The private ownership of ElectraNet also increases the likelihood that incentive regulation will function better (chapters 5 and 7).

ElectraNet also undertakes a RIT-T shortly before an augmentation project is due to begin, but this suffers from the same deficiencies as in New South Wales, Queensland and Tasmania.

Efficiency of standards

There are several deficiencies in South Australian reliability standards. As recognised by industry participants:

- Reliability standards may be too high. Standards for connection points were set to the level of reliability that existed when the state government owned and operated the network. The original reliability standards were not based on customers' value of reliability. The fact that a connection point cannot be re-

¹⁹ ElectraNet's planning and augmentation proposals are subject to public scrutiny by AEMO in the lead up to ElectraNet submitting its revenue proposal to the AER. While ElectraNet is not obliged to follow AEMO's advice in its proposal, AEMO's advice provides the AER with more information with which to assess the proposal.

classified to a lower level of reliability can entrench inefficient historical standards or fail to respond to new demand patterns.²⁰

- The lumpy nature of the reliability categories creates inefficiencies. There are only six (soon to be five) categories into which connection points can be classified. With a limited number of defined categories, it is not possible to take a more granular approach to reliability standards. Moreover, classifications are rounded up so that there is always a bias to a higher requirement for reliability.
- The lack of independent analysis of possible options (including non-network options) for achieving the reliability standard of a connection point calls into question whether the upgrade costs and options are efficient. While AEMO might be able to tell when the options and costs provided by ElectraNet are significantly overestimated, it has no recourse for identifying and recommending alternatives. AEMO recognises this in its review of capital expenditure by emphasising the need for detailed planning and capital assessments through the RIT-T (AEMO 2012d p. iii).
- The value of the VCR used in the cost-benefit analysis does not reflect possible differences in industry composition or customer preferences specific to South Australia.²¹
- Ultimately, AEMO's recommendations about the reliability categorisation of connection points are only recommendations — ESCOSA is under no obligation to accept them.
- There can be a gap of up to seven years between the timing of the reliability assessments for a connection point and the RIT-T for the relevant investments (AEMO, sub. 32, p. 11). Even if the reliability category applied to a connection point (and the preliminary costings of options used to set it) were efficient and reasonably accurate in the lead up to the revenue determination, this might not remain so by the time the investment close to commencement. As for New South Wales, Queensland and Tasmania, at the time that the RIT-T is carried out the required revenue has been approved, and the RIT-T process appears to be more of a formality rather than being a comprehensive review of the options, the detailed specification of the preferred option, and an updated estimate of the capital required to confirm the efficiency of the augmentation.

²⁰ For example, a large industrial user might move out of an area, causing maximum demand forecasts to fall significantly.

²¹ The VCR used in the calculations is extrapolated from the Victorian VCR (based on the Victorian survey in 2007) using data on sectoral demands for electricity (AEMO 2010e, p. 15).

Minimising administrative and compliance burden

The administrative and compliance burden of the transmission planning framework in South Australia appears to be moderate. The input of AEMO and ESCOSA and their interactions with the business, and the resetting of standards every five years impose some costs. However, in between revenue determinations, only AEMO's advisory role seems to differentiate the South Australian framework from those in New South Wales, Queensland and Tasmania.

NEM-wide effects

AEMO's involvement in South Australia through its advice to ElectraNet suggests a consideration of network effects and inter-regional solutions, at least with Victoria.

Auditing compliance to ensure reliability and efficiency in the long run

The Commission is not aware of any independent auditing of the facilities and operation of ElectraNet's network.

15.6 The AEMC hybrid model

In considering a possible national framework for transmission reliability, the AEMC has developed a preferred model. This is mostly set out in the second interim report of the Transmission Frameworks Review (2012b) and the Transmission Reliability Standards Review (2010a), the latter of which was largely endorsed by the MCE (2011). Through these reports (and others, including the National Transmission Planning Arrangements (2008a)), the AEMC has mapped out a set of reforms to reliability and planning in transmission networks, that seeks to address many of the concerns that have been discussed above.

For setting reliability standards in the NEM, the AEMC's preferred model is largely based on the planning framework operating in South Australia, with several amendments to address some concerns with it (as discussed above).

Briefly, the main features of the model are as follows:

- AEMO would develop a national template of deterministic standards to be applied to connection points (or 'some other readily understandable basis') in all transmission networks. This template is likely to be similar to the categories currently applied in South Australia.

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- Each jurisdiction would appoint a body to set reliability standards for each connection point in the regional transmission network. The standards could correspond to the national template or could differ if the jurisdiction considered this to be more appropriate.
 - The standards would be ‘economically-based’ and would take the ‘hybrid form’. While not specified in detail, the Commission understands that the process of applying a specific standard to each connection point would involve probabilistic analysis as currently done by AEMO in South Australia.
 - The MCE has stated that ‘the body responsible for setting reliability standards would be independent of the body required to meet the agreed standards’ (2011).
 - Every five years, the application of the standards in each network would be reassessed and connection points could have their standard changed to a higher or lower level of reliability depending on the preferences of customers in that area. There would also be an option for a ‘flexible approach’ under which a transmission business could apply to bring forward or defer an investment if it could show there were economic benefits to doing so.

For transmission planning in the NEM more generally, the AEMC has also recommended several additional planning requirements intended to better integrate local and national planning and to address concerns about an intra-regional bias of investment that might emerge from jurisdiction-specific deterministic criteria. According to these recommendations, AEMO’s role as the National Transmission Planner (NTP) would be expanded to include:

- identifying possible future inter-regional investments during the process of developing the National Transmission Network Development Plan
- reviewing draft annual planning reports and draft RIT-Ts of the transmission businesses, and highlighting where transmission businesses may be able to coordinate their investment programs or identify and agree on options in other regions that may help to address a constraint or reliability risk
- providing demand forecasts for each region for use as a starting point for the forecasts used in transmission planning. Transmission businesses would be required to explain any departure from these forecasts to the AER.
- acting in an expert advisory role, including to the bodies responsible for setting hybrid reliability standards in each jurisdiction
- administering (with AER oversight) a NEM-wide system of inter-regional transmission pricing to achieve recovery on a beneficiary pays basis of the cost of inter-regional investments, including from users located in different regions from the relevant investments

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- assuming the Last Resort Planning Power²² (LRPP) currently held by the AEMC.

To support AEMO in this role and to further pursue inter-regional connections in the NEM, transmission businesses under the AEMC's recommended model would:

- be required to consult with each other as they prepare their annual planning reports and RIT-Ts. They would need to promote identification and implementation of network investment options that cross regional boundaries, and explain why they had chosen not to proceed with an inter-regional investment that had been identified by AEMO in its national planning processes
- have their regulatory control periods aligned. Among other benefits, this would allow the AER to allocate the required revenue for inter-regional investment options to the transmission businesses concerned
- formalise the process in which transmission businesses provide input to the NTP. This would include a formal working group comprising representatives of the businesses and the NTP to coordinate local and national issues addressed in the National Transmission Network Development Plan.

Assessment of efficiency

The AEMC's preferred model extends the strengths of the South Australian model, and is significantly better than arrangements in place in Queensland, New South Wales and Tasmania.

Efficiency of investments

The main positive features of this framework are:

- the model would provide increased oversight of the planning and investment decisions of the transmission businesses in New South Wales, Queensland and Tasmania by formalising AEMO's role of reviewing the annual planning reports and RIT-Ts of the businesses. However, concerns remain about how influential these 'reviews' would be and whether formalising oversight by AEMO would

²² The Last Resort Planning Power would give AEMO the authority to direct a transmission business to undertake a RIT-T (but not to direct that investment must occur) for potential transmission projects if they are likely to relieve forecast constraints in parts of the network that connect regions in the NEM. To date, the current Last Resort Planner (the AEMC) has not used this power (AEMC 2012j).

lead businesses to make more efficient decisions than they currently do under AEMO's current, less formal, oversighting arrangements²³

- under incentive regulation, the model motivates a profit maximising business to identify and implement efficient options (within the constraints of the hybrid deterministic standards). The efficient timing of projects, however, will likely only occur where incentives are consistent across the five year regulatory period, which is currently not the case (chapter 5)
- AEMO's input into the demand forecasts the businesses use for their planning might also reduce the likelihood that the AER approves excessive investments and hence revenue allowances, based on inflated forecasts. However, to be effective, this would probably require that the businesses release all the information they use to determine their connection point demand forecasts. In the absence of this, the AER might find it difficult to question the businesses' evidence for departing from the AEMO-issued regional level demand forecast
- aligning revenue determination periods should help increase the information the AER can use to assess the efficient level of capex required to meet a given set of reliability standards.

On the other hand, some deficiencies remain, including that hybrid standards (which would be expressed deterministically) create a bias towards network solutions and hence are likely to influence a more constrained consideration of alternative options. This could be exacerbated by the current bias in the incentive regulation away from opex and towards capex (chapter 5).²⁴

Furthermore, the RIT-T process is not equivalent to a real options approach (such as that incorporated in AEMO's probabilistic planning process). Hybrid standards can, in theory, incorporate the changing detail reflected in probabilistic planning (Grid Australia, sub. 44, p. 6 and box 15.8). However, the AEMC's proposed hybrid approach cannot achieve this because connection points would only be classified into one of a limited number of pre-determined categories in five yearly intervals.²⁵

²³ The AEMC does not comment about whether AEMO would provide advice on draft revenue proposals (as they currently do in South Australia). However, that would be a likely feature of any implemented model following the AEMC's approach.

²⁴ An additional, but lesser, concern is that the requirement that Victoria relinquish its current approach could mean that any profits associated with exploitation of information asymmetries (with the regulator) and cost efficiencies encouraged by incentive regulation would be kept by SP AusNet. Given their foreign ownership, these transfers would actually also represent welfare losses to Australians.

²⁵ The flexible approach might reduce some of this rigidity but would probably not address all the limitations of this model.

Efficiency of standards

The efficiency of the standards in this model and the process of their identification are an improvement on the current approach in New South Wales, Queensland and Tasmania. This is because the standards are based on a cost-benefit analysis, determined by an independent party, and informed by ‘an expert’.

For South Australia, the capacity to move standards applying to a connection point up or down would be an improvement. For Victoria, a move away from a contemporary probabilistic assessment of each significant investment to pre-set deterministic standards would be a step backwards and would likely increase costs for customers in that state.

None of the other concerns discussed with respect to the standards in the framework currently operating in South Australia are currently addressed by this model as it has been currently outlined (including the lumpy nature of reliability categories; lack of independent analysis of options and costs while setting standards; the inappropriate VCR used; no requirement to accept AEMO’s recommendation for connection point reliability categorisation; and the potentially long gap between when standards are set and when the investments to meet them are made). Further, the implementation of a national template of categories of standards could possibly exacerbate the costs that result from ‘lumpy’ categories. Allowing jurisdictions to depart from this national template undermines the benefits from consistency across the NEM.

Minimising administrative and compliance burdens

It is difficult to assess the *administrative and compliance burdens* of this model without knowing exactly how the model would be rolled out across the NEM. Allowing jurisdictions to depart from the national template and set their own standards implies that separate bodies might exist in each jurisdiction to carry out probabilistically based cost-benefit analysis to identify efficient levels of reliability. This may not be transparent or efficient.

The compliance costs under this model for businesses in New South Wales, Queensland and Tasmania are likely to increase due to the changes required of the businesses and the ensuing transaction costs.

NEM-wide effects

The recent recommendations made by the AEMC (2012j) are intended to develop a framework for transmission planning that takes account of NEM-wide effects. The

introduction of a beneficiary pays system would remove an obstacle to inter-regional investments that currently exists and would be a positive step towards a more NEM-wide focus for transmission planning. However:

- it appears that the majority of the recommendations in this model for consultation, cooperation and independent scrutiny mostly formalise processes that already exist and no process has been identified to evaluate the effectiveness of this formalisation.
- the jurisdiction-based deterministically expressed reliability standards are likely to maintain the current intra-regional bias for investments. It is not clear that the increased cooperation between AEMO and the transmission businesses (as proposed by the AEMC) would completely solve this.
- the model makes little progress on appointing a body to comprehensively manage reliability in the national grid. Maintaining jurisdiction-based reliability standards and decisions on augmentations undermines this goal.

15.7 Summing up

It should be emphasised that there are no easy solutions for ensuring efficient transmission reliability and planning in the NEM (and indeed this is the experience internationally). A fundamental reason for this is due to the fact that, unlike for distribution networks, it is impossible to rely upon output measures and leading indicators to regulate reliability for transmission networks. All arrangements involve ‘big brother’ in one form or another, whether it be governments, a confederation of network businesses, or a single body, and there are compromises and judgments which must be made. A combination of transparency, accountability, consultation, specialist knowledge, independent decision-making and giving pre-eminence to consumer preferences are the essential components of a workable arrangement. However all arrangements have their pros and cons — there is not any perfect solution.

Nonetheless, the assessment of the existing planning frameworks for transmission reliability against the criteria set out in section 15.2 reveals the strengths and weaknesses of the various approaches.

Efficiency of investments

- Profit motivated businesses with strong incentives to cost minimise are more likely to identify efficient options for addressing a given reliability constraint. If

these incentives are weakened, or business choices are influenced by other objectives, this will not necessarily be the case.

- Identifying which option should be installed, how much it will cost, and when the project should occur is unlikely to be able to be undertaken with any level of certainty or efficiency years in advance of the project commencement. Technology changes, demand, external events and other cost drivers can all change significantly over the course of several years.
- Accurately specifying and costing projects and approving the associated revenue allowances for projects based on this knowledge, closer to their commencement, can help deliver cost savings to customers.
- Competitive tendering can assist in reducing costs and revealing innovation.
- Reliability can be enhanced using network and non-network solutions. Reliability settings (such as the type of standard) and regulatory settings (such as incentives) should not constrain or bias businesses in identifying the most cost-effective solution to deliver a reliability benefit.
- Independent analysis of costs and benefits can provide greater assurance to governments and consumers of the value of investments
- Transparency in assumptions and models helps generate confidence in investment choice.

Efficiency of standards

- Levels of reliability are only likely to be efficient if they are identified within a cost-benefit framework.
- A cost-benefit framework requires a measure of the value customers place on reliability, which is a function of the costs they incur when an interruption occurs. VCRs that are robust, current, and disaggregated by relevant area and customer type should be the cornerstone of reliability settings.
- Incorporating VCRs in a planning context requires information on the probabilities of interruptions, and these probabilities must account for all possible contingencies and their likely effects.
- The costs for transmission businesses of providing a reliable network and the costs to customers from interruptions change over time. Reliability settings need to be flexible to reflect the changing nature of the costs and benefits that underlie them.
- Planning standards and modelling should be transparent, with stakeholders able to query methods and results.

Minimising administrative and compliance burdens

- Transmission businesses (and their owners) have a conflict of interest if they are responsible for both setting reliability standards and meeting them. Reliability settings should be determined by an independent, non-conflicted, well informed third party.
- The process of setting reliability standards and for establishing efficient augmentation solutions should itself be as efficient as possible in terms of costs, timeliness and responsiveness.

Taking account of NEM-wide effects

- A planning framework should consider the costs and benefits of the effects that reliability settings in one network can have on another (that is, network effects).
- Desired levels of reliability should be delivered using a combination of intra-regional and inter-regional network and non-network solutions — that is, the net benefits should be maximised using a NEM-wide perspective.
- The risk of cascading failure across jurisdictions, the presence of network effects in interconnected transmission networks, and the importance of implementing inter-regional solutions to network constraints when beneficial to do so, suggests that the regulation of reliability in transmission networks in the NEM should be the responsibility of a NEM-wide authority, and not jurisdiction-specific.
- This NEM-wide authority would be best placed to take responsibility for managing the national grid by developing and managing national transmission flow paths and reliability standards.

Auditing compliance to ensure reliability and efficiency in the long run

- The difficulty of observing reliability outcomes in transmission networks is only addressed implicitly in the current frameworks. Economic regulations need to recognise the value of reliability and measure the latent and actual reliability of networks. If they do not, incentive regulations may lead to greater short-run profits at the expense of underinvestment in reliability.
- Auditing compliance with reliability standards, including redundancy, and continuing to model the probability of interruptions, to the greatest extent possible, would be required to counter any such motivations, even with standards in place. Auditing whether networks meet deterministic standards would appear to be considerably easier than checking whether probabilistic criteria have been followed appropriately. In Victoria, this issue was addressed by appointing an independent planner (AEMO) with the appropriate resources

and expertise. However, even in Victoria, there are grounds for auditing the delivery and performance of new investments, as well as maintenance and replacement projects.

15.8 The way forward

In the Commission's judgment, the way forward for transmission reliability and planning frameworks in the NEM should be through some form of national framework that takes account of the characteristics identified above. The analysis above effectively weighs up two competing alternatives, both of which have considerable advantages over the status quo:

- the AEMC's hybrid model
- an extension of AEMO's probabilistic planning, as it currently applies in Victoria, to the rest of the NEM (AEMO planner model). The Commission's preferred modifications to this model are discussed in the implementation section below.

The Commission's initial view is that, based on the criteria for assessment, the AEMO planner model offers better prospects for progress towards an efficient national planning framework for transmission reliability (table 15.2). The biggest drawback of the AEMO planner model is that it appears to impose larger administrative and compliance burdens.

Table 15.2 An illustration of possible progress from two national models for transmission reliability from current conditions
NEM-wide average

<i>Criteria</i>	<i>AEMC hybrid model</i>	<i>AEMO planner model</i>
Efficiency of investments		
Efficiency of standards		
Minimising administrative and compliance burdens		
Taking account of NEM-wide effects		
Auditing compliance to ensure reliability and efficiency in the long run		

However, it is important to assess whether this conclusion would change if several aspects of the AEMC model and the surrounding regulatory environment were improved.

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- *strengthening the incentives* under incentive regulation may improve outcomes under the AEMC hybrid model. The Commission has proposed privatisation and significant reforms to incentive regulations. If these were implemented, the efficiency of the AEMC model would be bolstered because businesses would have a greater profit motive to choose the least costly and most innovative approaches to achieving reliability standards. While the medium-term gains would mainly flow to shareholders, over successive regulatory periods, the AER would adjust revenue determinations so that consumers gained more of the benefits. (In contrast, the AEMO model would pass on identified cost savings to customers immediately, but might not always identify the most innovative or low cost option)
 - *using more categories for standards* would provide more options for optimising the network (solving the ‘lumpy categories’ problem identified earlier)
 - *using a single expert and independent body* to determine efficient options and costings in the standard setting process would provide rigor and independence to determination of standards. At present, the AEMC model does not rule this out, but specification of such a feature would strengthen its approach
 - *applying detailed and disaggregated* values of customer reliability (recommendation 14.1) would improve the reliability of the probabilistic approach, which would translate into more appropriate hybrid standards.

Strengthening the incentives under incentive regulation and addressing some of the shortcomings in the hybrid approach would bring the assessment of the costs and benefits of the two models closer together. Reaching a firm conclusion about the relative advantages of one model over the other, however, requires consideration of the relative magnitudes of the benefits encompassed in each of the criteria.

As discussed in chapter 14, delivering efficient levels of reliability, through probabilistic planning (by avoiding inefficient standards expressed deterministically), offers by far the biggest gains to customers compared to the status quo. Delivering reliability by choosing efficient options and passing on cost savings to customers could also deliver significant, but smaller benefits. The benefits from meeting the last three criteria compared to the status quo are much smaller.²⁶ Given this, the Commission judges that the AEMO planner model could deliver larger net benefits than the AEMC hybrid model. However, there are still

²⁶ The Commission considered, and then rejected, the use of benchmarking of the efficiency of reliability outcomes in South Australia (the hybrid model) compared with Victoria (the AEMO model). As discussed in chapter 4, it is unlikely that benchmarking analysis of this type would be accurate enough to make well-founded regulatory decisions.

some significant disadvantages to the AEMO planner model, which are discussed below.

Implementation

While the AEMO planner model offers the potential for significant gains for customers, concerns remain about its implementation throughout the NEM. As noted above, extending the Victorian model to the rest of the NEM would probably increase the *administrative and compliance burden* compared with alternative models. In regards to AEMO's role as a 'procurer', some participants in this inquiry have expressed concerns about the costs involved for businesses submitting tenders, for the incumbent transmission business, and for AEMO when carrying out the tender process in Victoria. It is not yet clear whether these costs are mostly due to the specific features of the tendering process in Victoria or to tendering processes in general. Nevertheless, there is a risk that any such costs could grow were the AEMO model adopted on a NEM-wide basis.

Some participants have also claimed that there are requirements to negotiate many contracts with different parties in Victoria, creating significant transaction costs. This could be because of failures to clearly assign liability during the privatisation process in Victoria. Any extension of the AEMO planner model to the rest of the NEM would require clearly allocating default liability settings as part of the implementation process, before any tenders were initiated. This would provide certainty to parties entering into the tendering process, and subsequently to those operating, and connected to, new augmentations, and would possibly largely resolve these transaction cost problems.

A tentative upper bound estimate of the costs of tendering processes in general is around eight per cent of the costs of a project.²⁷ However, transmission businesses often already tender for major parts of projects. Consequently, the incremental costs of tenders to address a constraint in a network may not be very different from tenders for a pre-specified scope or part of a project, such as installing a new substation. The transaction costs of introducing contestability would be minimised if it were introduced at the same time as a national framework for transmission reliability.

²⁷ Estimates have suggested that the costs of submitting a tender can be as high as five per cent of the project cost (AEMC 2012j, p. 80). The costs to AEMO of running a tender process could be in the realm of \$0.2-0.3 million, which would make the total cost of the tender process for a project of \$10 million as high as 8 per cent.

On the other hand, the benefits of tendering for separable augmentation may still be low. For example, this could occur if the market were shallow.²⁸ It is possible that there might be only a few businesses capable of proposing and designing creative solutions for relieving constraints, and able to subsequently coordinate and operate the entire project. Similarly, the gains may be small if the alternative options to relieve the constraint are well known or there is little scope for innovation.

However, contestability in markets is generally considered to be a desirable feature. Further, while SP AusNet has won the majority of tendered projects in Victoria, it is not possible to estimate their costs in the absence of the discipline of competition. Contestability is an important part of electricity network regulation in the United States (box 15.9).

Box 15.9 Transmission contestability in the United States

Federal Energy Regulatory Commission Order 1000

The Federal Energy Regulatory Commission (FERC) issued Order No. 1000 on July 21, 2011. Among other things, Order No. 1000 directed transmission planners to remove any 'right of first refusal' (wherein planners would be required to offer local transmission owners (TOs) the first option to build any given project, limiting contestability). The FERC did not mandate any particular manner of introducing contestability, but did require that planners demonstrate transparent, and non-discriminatory, criteria and evaluation processes for selecting projects.

Pennsylvania-Jersey-Maryland (PJM)

PJM covers 13 States (and the District of Columbia) in the eastern United States. PJM Interconnection is the Regional Transmission Organisation (RTO) with responsibility for market operation and planning. Where PJM Interconnection identifies an investment needed on reliability grounds (or upgrades existing facilities), it is allocated to the TO with responsibility for the relevant service territory.

For projects justified on economic (not reliability) grounds, PJM Interconnection's planning process allows a variety of participants to propose solutions to the identified need. PJM Interconnection assesses the proposals and recommends those that pass a cost-benefit test to its board. While TOs can participate, they are not guaranteed the right to construct a project. PJM Interconnection has successfully argued before FERC that this process is not a 'right of first refusal' (Wuslich et al 2012).

(Continued next page)

²⁸ However, introducing contestability into the whole NEM might encourage a deepening of the market over time.

Box 15.9 (continued)

California

The California Independent System Operator (CAISO) conducts a three phase planning process to identify and allocate transmission investments. In the third phase, CAISO conducts a competitive solicitation process to select the builder and owner of economically- and policy-driven (for renewable energy) projects. Reliability-driven projects are generally the responsibility of the incumbent TO.

New York

In planning for reliability purposes, the New York Independent System Operator (NYISO) conducts an assessment of the future reliability needs of its power system. It then requests market-based solutions from any qualified developer (not just TOs). If the market-based solutions do not address all reliability needs, NYISO can direct local TOs to construct a 'regulated backstop' solution.

For 'economic' planning, NYISO identifies high cost congestion paths, and seeks proposals for specific projects from developers. In order to be approved, and be eligible for regulated cost recovery, a project must meet three conditions — benefits exceed costs, the capital cost is above \$25 million and 80 per cent of the project beneficiaries must vote to approve it. If approved, NYISO allocates costs on a 'beneficiary pays' basis (discussed in chapter 19 on merchant interconnectors).

Source: NERA (2012c).

At this stage, the Commission judges that, on balance, it is not clear that the benefits of contestability offered by AEMO's role in Victoria as a 'procurer' outweigh the complexities and costs of this role. That is, the possible *administrative and compliance costs* associated with contestability could be larger than the benefits of contestability for the *efficiency of investments*. For this reason, the Commission's preferred model does not involve AEMO as a 'procurer'.

The Commission seeks information about the potential benefits and costs of introducing contestability into separable augmentations of the network, as currently occurs through the Australian Energy Market Operator's procurement role in Victoria, and in parts of the United States. The Commission seeks evidence from participants regarding the costs and benefits of contestability including:

- *administrative and compliance costs*
- *the depth of the market (present and potential)*
- *the extent of efficiency gains available from competitive pressures from contestability for solutions to constraints (as opposed to contestability in detailed construction of a given solution)*

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- *any ongoing cost inefficiencies caused by potentially additional separate owners and operators of the ‘separable’ assets connected to the network.*

The Commission also seeks participants’ views regarding the costs and benefits of auditing facilities and processes in transmission networks. What alternative methods are there for the regulator to gain assurance about inherent reliability, in terms of whether transmission businesses are doing either, what they should do (for example maintenance), or whether they have done what they said they were going to do (for example augmentations)? What is international best practice in this respect? What powers should the regulator have if an audit suggests poor compliance?

The Commission considers that several other improvements should be made to address remaining concerns about the implementation of the AEMO planner model throughout the NEM.

- The planner should be subject to greater scrutiny, especially considering the complexity of probabilistic planning processes. Within the NEM governance framework, the AER would be the most appropriate body to enforce transparency and regular reporting of modelling parameters, assumptions and results, and data inputs. Periodic review would also be appropriate to ensure that the planning framework was delivering optimal outcomes in accordance with the National Electricity Objective (NEO).
- Removing network planning from incumbent transmission businesses risks losing the in-depth and localised knowledge that planners in those businesses have accumulated. AEMO should therefore include incumbent businesses in all steps of their planning process and utilise this specific expert knowledge as much as possible, especially in the option identification stage. This interaction and cooperation would also allow AEMO to identify and choose options that exploit operational capacity in parts of a network and thereby make trade-offs between operational and investment decisions.
- The probabilistic process used should be international best practice, and would be strengthened by periodic peer review. One of the first steps, however, is to identify the deficiencies in the data collected by transmission businesses and AEMO, and establish the required collection and reporting processes.
- The VCR is one of the most critical parameters of probabilistic planning. For reliability outcomes to be efficient, VCRs must be identified in as disaggregated way as possible, including by:
 - geographical location
 - customer type

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- interruption duration.
 - The consequences of underestimating the VCR might include underinvestment, and over the longer-run, a greater frequency of outages. At the margin, the consequences of overestimating the VCR are likely to be less severe. Given the difficulties with estimating an accurate VCR and the fact that VCR is an aggregate of the differing preferences of many customers, adopting a VCR that is at the higher end of the reasonable range of possible values would be sensible. The ABS would be the most appropriate body to undertake the research required to reveal accurate VCRs (recommendation 14.1).
 - The revenue required for projects (separable and non-separable) should be agreed between AEMO and the incumbent business for projects below an appropriate threshold (or through arbitration with the AER when agreement cannot be reached) and communicated to the AER before the commencement of the project. For projects with costs above the threshold, the business should submit detailed costings, based on their own tenders and firm quotes to the AER. AEMO would also submit its own cost estimates to the AER. The final allowed expenditure should then be determined by the AER.
 - The AER should include the businesses' relevant expenditure for both separable and non-separable projects in the regulated asset base at the commencement of the next regulatory period. This would increase transparency and provide the AER with more information to improve benchmarking practices.
 - Revenue approved for inter-regional investments should be collected from jurisdictions according to their shares of the benefits derived from the investment.
 - AEMO would also carry out auditing of transmission networks, including auditing the performance and operation of critical equipment to ensure transmission businesses were appropriately augmenting and maintaining their networks for the purposes of reliability. It would report the outcomes of these audits to the AER.

The Commission's preferred model

In transmission reliability there are no perfect solutions — all options have pros and cons. While being conscious that the AEMC has reached a different judgment, the Commission considers that, with these changes made, the most effective framework for planning transmission networks in the NEM for reliability purposes would include a NEM-wide planner. AEMO would be the most qualified body to carry out the required functions.

As the national planner, AEMO's current functions in Victoria would be extended to all other regions in the NEM (but with some changes, for example, excluding the 'procurer' role).

As part of its cost-benefit analysis of possible augmentations to transmission networks, AEMO would use a probabilistic process, and the costs and benefits would be assessed on a NEM-wide basis to take account of possible network effects. AEMO would use the VCRs estimated by the ABS as recommended in chapter 14.

The AER would be responsible for ensuring AEMO's planning and auditing processes were transparent and consistent with the NEO.

AEMO would carry out these planning functions for the foreseeable future. However, periodic reviews of transmission reliability settings should be undertaken, with the option of removing AEMO from this role if the evolution of transmission pricing and access arrangements ultimately provide an alternative market-based solution. In particular, the AEMC and the Commission have recommended optional firm access to transmission lines by generators (chapter 18 and AEMC 2012j). This would create market signals for reliability and the relief of some network constraints. However, for the reasons given in chapter 18, it would be premature to discontinue planning for reliability purposes in the NEM until alternatives (such as including the option for market driven transmission investment for both generation and load) were demonstrated as effective.

Of course, just how well AEMO would carry out these functions as a planner throughout the NEM, and whether it would always make efficient decisions in line with the NEO, would depend upon adequate resourcing and effective governance. These issues extend to all institutions in the NEM, including AEMO in its current role as market operator. (Chapter 21 sets out principles of good governance in institutions with regulatory functions — box 21.1.) In considering the details of how this model might be implemented, this type of issue would need to be given careful thought.

Some stakeholders have raised concerns about legal liability and accountability in a model in which AEMO acts as the NEM-wide transmission planner. However, liability costs are likely to be ultimately met by consumers, regardless of the planning model. The most important question is the degree to which alternative models cost-effectively avoid major transmission failures. There are risks associated with the various models considered by the Commission in terms of:

- their cost-effectiveness in the case of models relying on deterministic standards

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- the potential for adverse network effects in models that have a less nationally-oriented focus
 - any ambiguities about responsibilities for reliability in the case of the Commission's preferred model.

On the latter point, the Commission understands that there have not been any reliability problems or ambiguity about responsibilities associated with joint roles of AEMO and SP AusNet in Victoria.

The Commission seeks further input on the potential advantages and disadvantages of the Commission's suggested alternative to the Australian Energy Market Commission's hybrid planning model. How could the Commission's preferred model be improved? Since a key objective of a national planning framework is to avoid costly system-wide failures, to what extent do the different models vary in their capacity to achieve that goal?

An adapted AEMC hybrid model?

A possible, but second best, alternative would be an adapted version of the AEMC's recommended hybrid model (all models are summarised in table 15.3 below). As previously outlined, the Commission believes that the AEMC model has benefits compared to the status quo but also some drawbacks compared to the Commission's preferred model. Some of these could be ameliorated by the following changes:

- AEMO would develop the national reliability template based on hybrid standards in consultation with all jurisdictions and the transmission businesses, and revisit it periodically. All jurisdictions would have to use the national template. AEMO should set the standards applied to connection points in all jurisdictions and in doing so, use the VCRs estimated by the ABS as recommended in chapter 14.
- AEMO would expand its advisory role to all transmission businesses, including for draft revenue proposals, as is currently done in South Australia
- Transmission businesses would be able to ignore AEMOs advice and make their investment decisions autonomously. However, they would still need to undertake a RIT-T. Most critically, in making revenue determinations, the AER would accept AEMO's advised transmission investments as the default, requiring the transmission business to show why its alternatives were more efficient. This would reverse the onus of proof for reliability-driven investment categories under the Rules.

Table 15.3 Summary table of alternative transmission planning models

	<i>AEMC hybrid model</i>	<i>AEMO planner model (as per Vic)</i>	<i>Commission's preferred planner model</i>	<i>Commission's modified hybrid model</i>
Type of reliability standard or planning?	Hybrid standards for connection points	Probabilistic planning	Probabilistic planning	Hybrid standards for connection points except for Victoria where probabilistic planning could be retained
Standards contained in?	National template and/or jurisdictional instruments. Reliability to remain as a state and territory function	Not specified but most likely reliability to become a national function	Reliability to become a national function	National template. Reliability to become a national function.
Who sets the standards?	Jurisdictions with input from expert advisor	AEMO	AEMO in consultation with transmission businesses	AEMO in consultation with transmission businesses
Who makes augmentation investment decisions?	Transmission businesses	AEMO	AEMO in consultation with transmission businesses	Transmission businesses
Process for planning or setting standards?	AEMO to develop national template. Standards to be 'informed' by jurisdictionally appointed body	AEMO probabilistic planning process	AEMO probabilistic planning process, peer reviewed and designed to be international best practice	AEMO to develop national template and set all standards
How is revenue allocated?	AER five yearly revenue determination process	Negotiation between AEMO and transmission business before start of non-separable projects. Contestability for separable projects.	Negotiation between AEMO and transmission business before start of small projects (with AER approval). Separate AER revenue determination process before start of large projects.	AER determination process with the onus of proof on transmission businesses to convince the AER to move away from AEMO recommended investment plan and costs
Independent cost-benefit analysis or RIT-T?	Businesses to conduct RIT-T with scrutiny by AEMO	Independent cost-benefit analysis	Independent cost-benefit analysis	Businesses to conduct RIT-T with scrutiny by AEMO
Last resort planning power	AEMO	Not specified	AEMO but with the added power of being able to direct investment if the need is considered critical	AEMO but with the added power of being able to direct investment if the need is considered critical

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- The functions of the last resort planning power would be changed to include a power to instruct transmission businesses to invest if AEMO feared underinvestment could expose the network to serious reliability problems. The AER would arbitrate on any final disputes. AEMO would also carry out auditing of transmission networks, including auditing critical equipment, to ensure transmission businesses were augmenting and maintaining their networks appropriately for the purposes of reliability.
 - The (superior) existing planning framework in Victoria would be preserved (if that were the preference of the Victorian Government), with the adapted hybrid model only applying to other jurisdictions. Other jurisdictions would be free to adopt the AEMO planner model.

In both of these alternative models, AEMO would set transmission reliability standards. Both models also currently exclude contestability in the procurement of investments and therefore might limit innovation and reduce opportunities for lower costs.

The main drawbacks of the Commission's modified AEMC hybrid model would be that the levels of reliability delivered are less likely to be efficient and the risks of NEM-wide effects would not be fully accounted for. Jurisdiction-based planning would perpetuate concerns about the intra-regional bias of investments. Moreover, under this alternative, the type, timing and cost of investments are less likely to be efficient. These drawbacks would tend to increase network costs relative to the Commission's preferred model.

In an environment of rising electricity prices, what difference might these changes make?

It is difficult to estimate precisely the net economic benefits of moving to the Commission's preferred national planning framework. This would require detailed modelling that is currently not possible because of existing data deficiencies.

However, the following examples suggest that the net economic benefits would be significant.

- Deterministic standards have implicit VCRs and it is possible to assess whether augmentations to meet deterministic standards are close to efficient by assessing whether the implicit VCR seems reasonable. For example, AEMO cites a proposed investment in New South Wales to meet an N-1 standard that implied a VCR of \$9 million per MWh (around 150 times the estimate AEMO uses in Victoria). This does not seem reasonable and indicates room for significant savings.

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- Comparing augmentation plans to meet N-1 deterministic standards with plans that would pass a probabilistic cost-benefit test can reveal differences in costs. In these analyses, the identified savings usually result from deferring investments rather than not augmenting at all. AEMO estimated in 2011 that probabilistic planning in Victoria allowed them to defer \$550 million of investment compared to what would have been required under an N-1 deterministic standard. Assuming that similar savings could be identified in all regions of the NEM, these savings could be as high as \$2–3 billion. At some point in the future, at least some of this investment is likely to be required. Deferring this investment for one revenue period with a discount rate of 8 per cent would produce savings with a net present value of almost \$1 billion.

This is not an unreasonable assumption considering that:

- in some regions deterministic standards can include standards that require more redundancy than N-1
 - of all the regions in the NEM, the comparatively higher customer density of the network in Victoria makes it more likely to be able to justify investments to meet N-1 standards under a cost-benefit analysis, suggesting larger differences might exist in other parts of the NEM.
- In New Zealand, augmentations required to meet deterministic criteria were found to be required eight years earlier than they would under a probabilistic cost-benefit analysis. Two types of avoided costs might emerge from deferring investments:
 - analysis in New Zealand suggested customers save \$75 000 per \$1 million of investment deferred (or around 7.5 per cent) over eight years
 - considering the possible changes in technology, customer preferences, and prices that can occur in eight years, new and cheaper alternatives might be available in the future.

15.9 Delivering reliability in the shorter term

Augmenting networks according to a detailed planning process is one facet of network quality. Network businesses also need to:

- operate their networks safely
- maintain their networks in good working order and make repairs
- deal with possible causes of faults where possible, such as removing vegetation growing close to equipment
- respond quickly to restore supply when an interruption occurs.

Service Target Performance Incentive Scheme

The AER developed the Service Target Performance Incentive Scheme (STPIS) for transmission to encourage transmission businesses to maintain network reliability through actions other than building in redundancy.

The STPIS sets targets for:

- circuit availability — the proportion of time that all elements of the network are working and available
- the frequency of outages
- average outage duration
- market impact — designed to encourage businesses to improve availability at times, and on those elements of the network, that are most important to determining spot prices.

Businesses incur penalties (rewards) if they perform below (above) their targets, which are calculated as a percentage of their maximum annual revenue (MAR), referred to as ‘revenue at risk’. The maximum reward or penalty for the three service components of the STPIS in total is 1 per cent of MAR, while it is 2 per cent for the market impact component. The targets, weights for each criteria, and total revenue at risk are unique for each business. In general, targets are set using an average of historical performance over the previous five years, although businesses can propose an alternative target to the AER.

The rewards and penalties are capped, however, they might not be symmetric, depending on the distribution of the historical data.

Notwithstanding the current review of the STPIS, transmission businesses appear to have responded positively to the incentives offered under the scheme (AER 2011e), suggesting that the costs of improving performance have been less than the rewards available. This type of incentive regime, in theory, removes the need for benchmarking these elements of reliability performance, because so long as the potential rewards (penalties) are large enough, a profit motivated business would have an incentive to search for efficiency gains to meet the reliability targets. However, if rewards are too high, customers would pay more for reliability improvements than they cost to achieve.

In the context of a national framework for reliability with a national planner using a probabilistic approach, the STPIS would become an important driver of reliability performance for several reasons.

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- To ensure they deliver a reliable supply, transmission businesses would need to rely on operational and performance actions, such as those underlying the criteria in the STPIS, because they would have less control over the level of redundancy in their networks.
 - Probabilistic planning is likely to reduce the redundancy in at least some parts of the NEM, which might result in more and longer interruptions to supply unless businesses improve their maintenance, operation and response outcomes.
 - Less redundancy in the network might lead to increased congestion on some lines at certain times, especially if the business is carrying out maintenance on that part of the network, which would increase the relative importance of the market impact measure.

Any changes to the STPIS to reflect the increasing importance of operational, maintenance and performance outcomes under a new national planning framework should consider the evaluation criteria already used by the AER in the current review (2011e, p. 12) to ensure that businesses retain the incentive to provide a reliable network up to the point that it is efficient to do so.

Dynamic and static equipment ratings

Transmission businesses determine how much power can flow through their equipment at any time. They ensure that they meet the network security standards set out in the Rules by specifying the maximum load that a line or other equipment can carry (so-called equipment ratings).

Network elements can carry different loads in different ambient conditions. In hot, still weather, lines heat up more quickly and droop further, increasing the likelihood of arcing.²⁹ To recognise that, on average, safe loads can be higher in winter than in summer, and at night than in the middle of the day, transmission businesses vary the maximum load (rating) that lines and equipment can carry. This is currently achieved in two ways.

Static ratings set out the loads that lines or other equipment can carry at different times of the day in different seasons and in some cases, in specific months. These ratings are based on the ambient conditions expected to occur (not those that actually occur) at each time, plus a margin of error for unseasonably high temperatures.

²⁹ Arcing is when electricity flashes over from one piece of equipment to another, or something else, such as a tree, creating a fault on the network.

Dynamic ratings measure the ambient temperature around equipment and sometimes the wind speed, and relay this information to operators so that the maximum safe load for that specific point and time can be utilised. On average, lines and equipment with dynamic ratings are used to a higher capacity than those with static ratings. For example, a line with a static rating on a cool, windy night in summer will likely have spare capacity on it.

Ratings that fail to utilise this dynamic approach can be costly where they lead to:

- higher cost generators being dispatched along other parts of the network due to lines reaching their ‘maximum’ static (but not dynamic) load
- network businesses augmenting their networks earlier than necessary because lines are running close to their specified maximum static (but not dynamic) loads.

Static ratings may lead to significant underutilisation of network assets compared with dynamic ratings (with some estimates suggesting that utilisation for some assets could be improved by around 65 per cent for a period of time without any loss of safety). This appears to be one area where large cost savings could be made without sacrificing reliability outcomes.

There has been some adoption of the technologies required to implement dynamic ratings, but the take up has been uneven across the NEM. Victoria has the highest proportion of its network operated with dynamic ratings. It is not clear why the rate of adoption of dynamic ratings has been slow, although the distortions created by the incentives in the regulatory regime (chapter 5) could be one explanatory factor.

15.10 Changes to transmission reliability

As the discussion above illustrates, there are many complex issues involved in the setting of reliability standards, their application in the transmission planning process, and other influences on the delivery of reliability in the short term.

Unsurprisingly, there is no single, ‘silver bullet’ solution. Accordingly, the Commission’s proposed improvements for transmission reliability (set out below) encompass a range of topics including technical settings of reliability, responsibility for and transparency in planning and interaction with incentive regulation. These should not be considered on an individual basis, but rather taken as a package of reform for transmission reliability.

The Standing Council on Energy and Resources should, in consultation with the Australian Energy Market Operator and the Australian Energy Market Commission, develop a National Electricity Market-wide reliability framework in which reliability settings would be determined by customer preferences.

This framework should replace all jurisdiction-specific reliability settings.

Drawing on the current Victorian experiences, the Australian Energy Market Operator should carry out transmission planning for all transmission networks in the National Electricity Market. The Operator should:

- use Values of Customer Reliability (as obtained through draft recommendation 14.1)*
- use best practice probabilistic processes in its cost-benefit analysis of network and non-network options to address reliability issues and/or constraints*
- describe its full cost-benefit analysis as part of its process for the Regulatory Investment Test for Transmission*
- make public all methodologies, parameters, data and other inputs used in the analysis*
- work closely with each of the transmission companies concerned to make sure that their experience and input is fully understood and where mutually agreed, appropriately incorporated into the analysis*
- use its best estimate of peak demand forecasts, having sought input from all relevant stakeholders*
- ensure that planning decisions are consistent with National Electricity Market-wide efficiency objectives*
- not carry out the ‘procurer’ role currently done in Victoria until it can be demonstrated that the benefits of such an approach exceed the costs in the Australian National Electricity Market environment.*

In consultation with the transmission network businesses, the Australian Energy Market Operator should specify the details of the network or non-network solution to an identified constraint.

If the cost of the solution is less than an appropriate threshold, then:

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- *the Australian Energy Market Operator and the network business should negotiate and agree on the required expenditure. If there is no agreement, the Australian Energy Regulator should determine the allowable spending.*

If the costs exceed the above threshold, then:

- *the transmission business should submit detailed and final costings to the Australian Energy Regulator*
- *with advice from the Australian Energy Market Operator, the Australian Energy Regulator should determine the allowable expenditure.*

The Australian Energy Regulator should automatically include the relevant agreed allowable expenditure in the revenue allowance for the transmission business.

At the next regulatory reset, the actual capital spent on such projects should be included in the transmission business's Regulatory Asset Base.

DRAFT RECOMMENDATION 15.4

The Australian Energy Regulator should ensure that, in the Australian Energy Market Operator's role as a transmission planner, its public reporting and planning processes are adequate, transparent and meet the National Electricity Objective.

DRAFT RECOMMENDATION 15.5

The Australian Energy Market Operator should review and, where necessary improve, the technical aspects of its probabilistic processes, particularly those relating to low-probability, high risk events. In undertaking the review, the Australian Energy Market Operator should closely consult with network businesses and seek independent peer review of its technical methods.

DRAFT RECOMMENDATION 15.6

If the Standing Council on Energy and Resources does not accept draft recommendations 15.2 and 15.3, then it should implement a second best option in which:

- *transmission businesses would retain the function of planning and making augmentation decisions*
- *the Australian Energy Market Operator would set hybrid standards for connection points every five years, with standards that could fall as well as rise, and would provide advice on efficient investment to meet those standards*

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- *in consultation with network businesses, the Australian Energy Market Operator would develop peak demand forecasts. The Australian Energy Regulator would use these demand forecasts in its regulatory determinations in accordance with draft recommendation 8.4*
 - *the National Electricity Rules should be amended to allow the Australian Energy Regulator to accept the Australian Energy Market Operator's advice on the preferred network and non-network options and their cost as the default proposal, requiring the transmission business to show why its alternative was more efficient*
 - *the Victorian Government should not be required to relinquish its current planning framework, with the adapted hybrid model only applying to other jurisdictions. Other jurisdictions should be free to adopt the Victorian planning model.*

DRAFT RECOMMENDATION 15.7

Where necessary, the Australian Energy Market Operator should assist the Australian Energy Regulator in its compliance and auditing of transmission networks, to ensure that the agreed projects are completed and intrinsic network reliability is maintained.

DRAFT RECOMMENDATION 15.8

The Australian Energy Market Operator should act as the planner of last resort where it considers that underinvestment could expose the network to serious reliability problems, with the right to direct investment should the Australian Energy Market Operator believe that not to do so could seriously compromise the reliability of the National Electricity Market. The Australian Energy Regulator would act as an arbitrator in any disputes.

DRAFT RECOMMENDATION 15.9

The Australian Energy Regulator should review the Service Target Performance Incentive Scheme for Transmission to ensure the incentives and targets are consistent with the new National Electricity Market-wide reliability framework.

DRAFT RECOMMENDATION 15.10

Transmission businesses not already using this approach should transition to dynamic capacity ratings on all critical equipment.

16 Distribution reliability

Key points

- Reliability in distribution networks is usually measured by the frequency and duration of power interruptions, rather than the likelihood of interruptions as is the case in transmission networks
- Most power interruptions that customers experience are as a result of faults or failures in distribution networks.
- Distribution reliability varies significantly between jurisdictions, and businesses in the National Electricity Market (NEM) because it is affected by the specific characteristics of each network and the standards imposed.
- In order to influence the reliability of distribution networks, state and territory governments and regulators apply reliability standards to distribution businesses, and the Australian Energy Regulator (AER) applies the Service Target Performance Incentive Scheme (STPIS).
 - This causes duplication and inconsistencies in the standards for some businesses, increasing their costs and making benchmarking of distribution businesses difficult.
- Inappropriate reliability standards can also introduce inefficiencies:
 - standards that are too high or too low impose (net) costs on customers.
 - standards that restrict the choice of combinations of inputs that distribution businesses can use to achieve improved reliability (such as planning, maintenance and responding quickly to outages) increase costs to businesses and consumers.
 - requiring distribution businesses to adhere to, and report on, different standards, administered by different regulators, increases costs to businesses and consumers.
- A national reliability framework for distribution businesses could overcome these inefficiencies and facilitate benchmarking. It should:
 - remove jurisdiction-specific reliability standards
 - reflect customers' preferences through estimated values of customer reliability
 - apply all components and parameters of the STPIS to all businesses
 - streamline reporting requirements
 - set efficient standards
 - ensure incentives are efficient and reflect customer preferences.

16.1 Introduction

Distribution businesses seek to deliver reliable electricity supply to customers by planning, building, and maintaining networks to avoid outages, and by responding to outages promptly when they occur.

For distribution businesses in the National Electricity Market (NEM), delivering reliable supply to customers can be challenging due to:

- the characteristics of distribution networks. Distribution networks are made up of many physical components varying in age and condition and often spanning large distances
- the environments in which they operate. Some distribution networks deliver electricity to customers in difficult environments with inclement weather. Wind, lightning, birds, possums, cars, and contact with trees can affect overhead lines. Density of customers in different areas also affects reliability, with rural areas more likely, on average, to experience longer interruptions.

Reliability standards are applied to distribution networks to encourage the network businesses to maintain high levels of reliability even though there are factors that affect reliability that are beyond the control of businesses. Unlike most reliability standards for transmission networks, these standards are commonly (but not always) directly linked to customers' experience of reliability.

There are several reasons why this customer-focused interpretation of reliability is appropriate for distribution networks:

- The majority (around 80–90 per cent) of power interruptions that customers experience occur as a result of faults or failures in distribution networks.
- Distribution networks are typically radial, rather than meshed, which limits the effects of an outage. Cascading failures between such radial networks are much less likely to occur. Therefore, the measures a distribution business takes to increase reliability usually only affect customers of that business. Similarly, changes to reliability in distribution networks do not cause the 'network effects' that occur in transmission networks. Reliability outcomes in distribution networks can therefore differ markedly between businesses without creating significant adverse effects on other networks in the NEM.
- Because distribution networks generally have more line length than transmission networks, reducing interruptions by building redundancy into the majority of distribution networks would have a prohibitively high cost.

These characteristics are reflected in the metrics that are used to measure distribution reliability outcomes (box 16.1). The ‘system average interruption duration index’ (SAIDI) and the ‘system average interruption frequency index’ (SAIFI) are the two most common measures of reliability performance in distribution networks. They describe for how long and how often a customer could expect to be without power over a given period of time (usually a year).

Box 16.1 Common metrics of reliability in distribution networks

- SAIDI — system average interruption duration index — is the total minutes on average that a customer could expect to be without power over a given period, usually a year. SAIDI is calculated by adding the total duration of each customer interruption and dividing that by the total number of customers. Separate indexes can be calculated for planned and unplanned interruptions.
- SAIFI — system average interruption frequency index — is the number of times in a year that a customer could expect to experience an interruption. SAIFI is calculated by dividing the total number of interruptions across customers by the total number of customers. Separate indexes can be calculated for planned and unplanned interruptions. SAIFI does not usually include ‘momentary’ interruptions lasting for less than one minute.
- CAIDI — customer average interruption duration index — is the average time a customer could expect to wait to have supply restored after an interruption. CAIDI is calculated by adding the duration of each customer interruption and dividing that by the total number of interruptions (that is, SAIDI divided by SAIFI).
- MAIFI — momentary average interruption frequency index — is the number of momentary interruptions lasting less than a minute that a customer could expect to experience in a year. MAIFI is calculated as the total number of momentary interruptions across all customers divided by the total number of customers.

16.2 Reliability performance of distribution businesses in the National Electricity Market

Over the last ten years, average state and territory reliability performance data reflect reasonably consistent performance. International comparisons similarly show that the relative performance of Australia’s distribution businesses overall has been quite stable over time, though the NEM has consistently recorded significantly higher average SAIDI results than networks in many other countries.¹

¹ For example, the Brattle Group (2012a) compared average SAIDI results for the NEM with Italy, New Zealand, the Netherlands, New York, the United Kingdom and California to find that

Aggregate SAIDI results for jurisdictions and for the NEM as a whole, however, mask the variation in performance between distribution businesses, and even reliability performance data for a single distribution business may mask significant variations in the experience of customers in different parts of that business's network.

Participants in this inquiry have suggested that many factors contribute to variation in reliability performance between and within distribution businesses over time:

Reliability is ultimately the key measure of the performance of a network and a [distribution business]... major events such as storms, the network design (planning standards/network type CBD/Rural/Urban) and the condition of the network have a major influence on this measure. (Ausgrid, sub. 19, p. 2)

... comparisons between jurisdictions can be difficult, as factors such as the level of customer density, the size of the network and the terrain it covers, and environmental factors (e.g. exposure to extreme weather) can have a significant impact on the reliability performance which is achieved and the costs of augmenting and maintaining each network. (AEMC, sub. 16, p. 2)

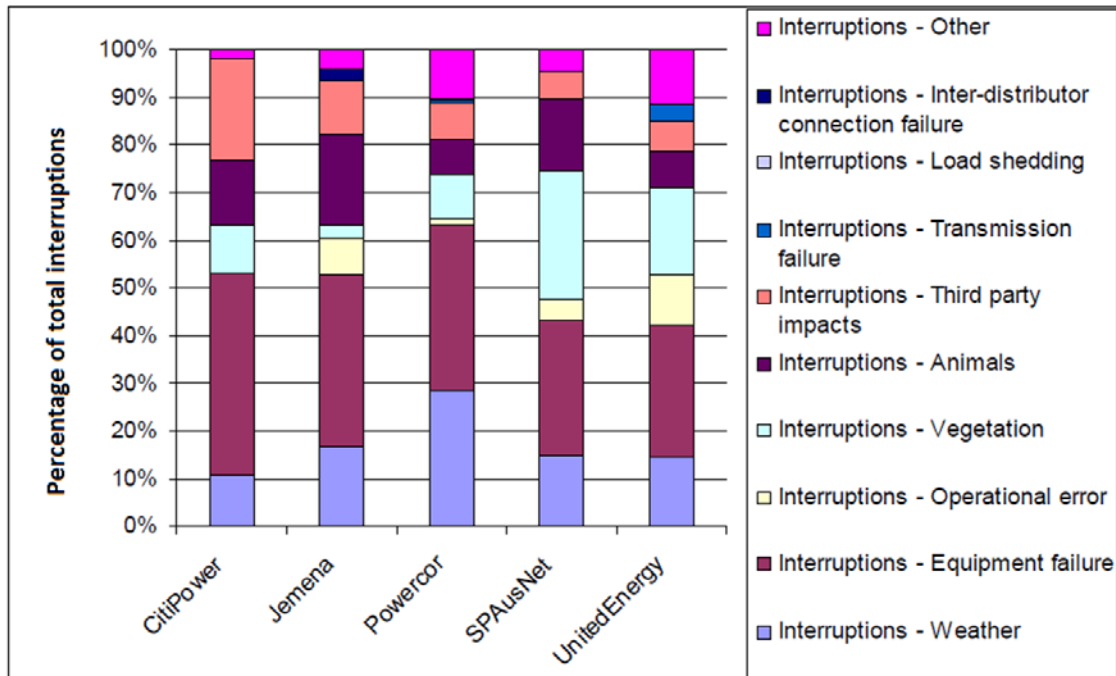
Some factors affecting reliability, such as the condition of the network and the level of redundancy, are controlled by the business. Others, such as severe weather events and customer density, are not. For example, some networks — and especially those in rural areas of the NEM — are 'stringier' than others with long lines, low customer densities and, on average, lower 'redundancy'.² These characteristics increase the likelihood of interruptions, and longer outage durations (for example, if maintenance crews must travel long distances).

In 2010, distribution businesses in Victoria attributed around 32 per cent of customer interruptions to equipment failure (AER 2012h, p. 38). Other common causes were vegetation falling on lines and weather events (figure 16.1). The significance of these causal factors varies across businesses. For example, SP AusNet's distribution business recorded a high proportion of interruptions caused by vegetation, which it attributed to 'the nature of the environment of the network' (AER 2012h, p. 39), whereas Powercor had proportionately more interruptions from the weather.

performance had shown no trend anywhere except in Italy where reliability appears to be improving.

² Redundancy involves the duplication of critical components to reduce the likelihood that a fault or failure will cause an outage to occur.

Figure 16.1 Causes of supply interruptions in Victorian distribution networks
2010



Data source: AER (2012h, p. 39).

Distribution businesses can address common causes of faults in various ways, including by building redundancy into their networks to address some equipment failures, clearing vegetation away from overhead lines, installing animal shields on poles and building new lines away from roads. The mix of planning, operational and maintenance actions that distribution businesses take to deliver reliability to their customers is in turn a function of the:

- characteristics of each network, including the environments in which each operates, and the densities and types of customer
- regulatory frameworks (in each jurisdiction and NEM-wide) including reliability standards and incentive schemes.

An efficient distribution business will deliver high reliability outcomes, given the characteristics of the network, for a low cost, using instruments within its control to mitigate the effects of factors outside its control. Benchmarking could be used to identify these businesses.

As discussed in chapter 14, and in a similar vein to the discussion of reliability settings for transmission in chapter 15, efficient reliability levels for distribution networks have two dimensions.

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- The framework for setting reliability should seek to achieve overall economic efficiency, so that costs of improving reliability are broadly equivalent to the benefits for customers from that improvement (that is, the marginal costs are equivalent to the marginal benefits). Regulatory benchmarking can help in the development of such a framework by highlighting instances where this benefit cost trade-off is integral to the process of determining reliability standards.
 - Businesses should meet reliability standards efficiently, with their capacity for doing this tested through traditional benchmarking tools (chapter 4).

16.3 Reliability settings for distribution networks in the National Electricity Market

As discussed in chapter 14, under incentive regulation network businesses have an incentive to reduce costs by reducing reliability. Governments and regulators therefore apply reliability standards to complement incentive regulation in the NEM. The frameworks in which these standards are applied to distribution businesses differ between jurisdictions (tables 16.1).

Distribution businesses in the NEM are required to plan and build their networks to meet the security requirements contained in schedules 5.1a and 5.1 of the National Electricity Rules (the ‘Rules’). Apart from this requirement, ‘service reliability standards’ are state and territory functions (SCER 2011, p. 2).

Reliability standards applied to distribution businesses in the NEM can include:

- design planning criteria such as deterministic planning standards, or probabilistic requirements that customer benefits of network augmentations outweigh the costs
- reliability performance standards, which are usually measured using SAIDI and SAIFI, that are applied through state and territory regulatory instruments (for example, codes and licence conditions) as well as under the AER’s Service Target Performance Incentive Scheme
- ‘worst served’ requirements protecting customers who experience significantly poorer reliability outcomes than the average

In addition, distribution businesses may be required to make guaranteed service level payments to compensate customers when reliability standards are not met.

Table 16.1 Jurisdictional reliability planning and performance requirements

<i>Jurisdiction</i>	<i>Planning criteria</i>	<i>Performance measures^a</i>	<i>Performance measures applied to?</i>	<i>STPIS - current or due to commence?</i>	<i>Jurisdictional performance measures consistent with or additional to STPIS</i>
NSW	Deterministic, set out in licence conditions	SAIDI, SAIFI standards set out in licence conditions	Feeder type	2014	Unknown until STPIS introduced
Vic	Probabilistic	SAIDI (planned and unplanned), SAIFI (exc. momentary interruptions), MAIFI, CAIDI set by DNSPs in line with STPIS targets set by AER	Feeder type	Currently in operation	Consistent
Qld	Deterministic, set by DNSPs in network management plans	SAIDI, SAIFI set out in Code ^b	Feeder type	Currently in operation	Additional
SA	Deterministic, set by DNSPs	SAIDI, SAIFI set out in Code ^c	Region	Currently in operation	Additional
Tas	None	SAIDI, SAIFI set out in Code ^d	Customer category	Currently in operation	Additional
ACT	None	SAIDI, SAIFI, CAIDI minimum targets set out in Code ^e	n/a	2014	Unknown until STPIS introduced

^a In some jurisdictions, SAIDI and SAIFI performance standards apply only to unplanned outages. ^b Queensland Electricity Industry Code Electricity Distribution (Supply Standards) Code; ^c South Australian Electricity Distribution Code; ^d Tasmanian Electricity Code; ^e Electricity Distribution (Supply Standards) Code.

Source: AEMC (2012k).

Within these types of standard, significant variation exists between jurisdictions and even businesses within a jurisdiction. This variation in type and level of standards can affect how easily distribution businesses can be benchmarked, since reliability standards are generally outside of the control of businesses but have a large effect on costs.

Costs can also arise when the type, level, and combination of reliability standards applied to each distribution business are not efficient. For example, standards might not be set in a way that allows (and encourages) the business to provide reliability for a low cost, and at a level that reflects their customers' preferences. There are

three main dimensions of cost and inefficiency in reliability standards for distribution networks in the NEM:

- levels of reliability that are too high or too low will not equate benefits and costs — imposing unnecessary price imposts on customers if too stringent, or resulting in excessive outage related costs if too low (chapter 14)
- restrictions on the way that businesses deliver improved reliability can needlessly increase the costs of providing distribution services to customers
- it is costly to meet and report on reliability performance against standards. Hence standards with duplicative, overlapping or different reporting requirements inflate compliance costs to businesses. These costs increase further if applicable sets of standards are inconsistent with each other.

These three types of inefficiency provide a framework to assess whether reliability settings for distribution businesses in the NEM are contributing unnecessarily to costs for customers. This framework is used below to assess the consequences of different reliability standards applied in the NEM on costs to customers, keeping in mind the role that standards play under incentive regulation — an exercise of regulatory benchmarking. An assessment is also made of how current standards might hinder, or facilitate, benchmarking of the managerial efficiency of distribution businesses.

Planning standards

In New South Wales, distribution businesses must comply with deterministic planning standards, which are set out in the businesses' licence conditions (a description of deterministic standards in the context of transmission networks is contained in box 15.2). The standards were introduced in 2005 by the New South Wales Minister for Energy. Before then, businesses were responsible for determining the appropriate level of reliability (AEMC 2012i). These higher planning standards have been one of the main drivers of increases in capital expenditure by New South Wales distribution businesses and in customer bills (Brattle Group 2012a).

Although businesses in other states and territories use deterministic standards to some extent, they have more discretion in the way they are used and the levels at which they are set. In Queensland, Energex and Ergon Energy use explicit deterministic standards to plan their networks. SA Power Networks sets deterministic standards to help it meet the performance targets set by ESCOSA and the reliability requirements set out in the South Australian Electricity Distribution Code. The deterministic standards, however, are not strict, and investments are

deferred when the risk of contingencies can be dealt with using other operational actions (ETSA Utilities 2012b, p. 7).³

In Victoria, CitiPower and Powercor Australia use deterministic standards for small, localised upgrades (CitiPower and Powercor 2012, p. 2). The Victorian Electricity Distribution Code specifies that businesses must develop plans to ensure reliability is delivered with consideration of high cost, low probability events. Mostly, distribution businesses in Victoria use probabilistic planning when making their planning decisions (the probabilistic process they use is similar to that used by AEMO for transmission in Victoria and is described in box 15.4).

Consequences for efficiency

Distribution businesses that are required to comply with higher deterministic planning standards will generally have higher capital expenditure, and this would need to be accounted for, as far as possible, in any benchmarking exercise.

There are also costs in specifying how a distribution business should plan its network in regard to meeting reliability standards. These costs arise from the substitutability between reliability ‘inputs’. For a given level of reliability, the lowest cost combination of inputs (redundancy, maintenance, operational flexibility, and others) is different from one business to the next and even within a business over time. According to Jamasb et al. (2010):

Due to the presence of possible trade-offs between Opex and Capex ... utilities might adopt different strategies to combine operating and capital inputs to improve service quality. (p. 5)

Deterministic planning standards therefore reduce the flexibility of a business to find the most efficient input mix to ensure reliability.

There are, however, some benefits of setting deterministic planning standards for distribution businesses. Requiring a distribution business to maintain a level of redundancy ensures that the business does not defer augmentations that are needed to maintain reliability in order to reduce costs under incentive regulation. These benefits largely drove the recommendation for the use of deterministic standards in Queensland as described in the Somerville report (2004), which included the recommendation that distribution businesses in Queensland adopt deterministic

³ Operational actions might include diverting supply through another route or temporarily running equipment at a higher rate of utilisation until the fault can be rectified.

standards of the form N-1 (box 15.4).⁴ These standards, however, have imposed high costs on Energex and Ergon Energy and it is not clear that the resulting increased levels of reliability are adequately valued by customers. Both distribution businesses have recently suggested that the deterministic standards be scaled back, with ensuing cost savings of \$505 million in the current regulatory period (Somerville 2011, p. 74).

Customers would only be willing to pay for augmentations to a distribution network to meet deterministic standards if they value the increasing reliability more than the price increases arising from the cost of the required investments (chapter 14). There is little evidence to suggest that the deterministic standards applied in New South Wales and Queensland are the result of an analysis of customer value of reliability and consequently, the likelihood of those standards being efficient is low.

While this type of inefficiency is less likely to exist for distribution businesses that use probabilistic planning (as it uses a cost-benefit framework), there are costs attached to undertaking a full probabilistic assessment every time a constraint emerges on a distribution network.

Jurisdiction-specific performance standards

Distribution businesses are required to meet performance standards set at the jurisdictional level, and at the national level through the AER's STPIS. Distribution businesses in Queensland, Tasmania, South Australia, and Victoria are currently operating under the STPIS. In Queensland, Tasmania and South Australia, state governments and regulators also apply different and additional performance targets to distribution businesses. In Victoria, distribution businesses are required under the Victorian Electricity Distribution Code to set their own SAIDI and SAIFI targets but all of the businesses have currently chosen to adopt the STPIS targets set by the AER. In this way, distribution businesses in Victoria are not subject to additional jurisdiction based standards. Whether the jurisdictional standards in New South Wales and the ACT will continue to apply in addition to the STPIS will be determined when the STPIS comes into force in 2014 and 2015, respectively.

Performance standards are set most commonly using SAIDI and SAIFI performance indicators (for example, table 16.2) although in some jurisdictions, there are also standards for MAIFI and CAIDI. In most jurisdictions, performance standards are determined according to feeder type — whether they are CBD, urban, or short or long rural feeders. Categorising performance targets by feeder type recognises that

⁴ For example, the Panel recommended, 'that for assets as important as bulk supply sub-stations, "N-1" should be the standard used'(p. 15).

those feeders that are longer, have less redundancy and are further from maintenance crews, generally have lower reliability and that these feeders generally service areas with lower customer density. South Australia, however, does not use feeder types, but rather sets standards for seven regional areas, and Tasmania classifies each community into one of five customer categories (critical infrastructure, high-density commercial, urban and regional centres, high density rural, and low density rural) with corresponding performance targets.

Table 16.2 Queensland distribution network performance targets
2010-11

<i>Distribution business</i>	<i>Feeder type</i>	<i>SAIDI (minutes) per year</i>	<i>SAIFI per year</i>
Energex	CBD	15	0.15
	Urban	106	1.26
	Short-rural	218	2.46
Ergon Energy	Urban	149	1.98
	Short-rural	424	3.95
	Long-rural	964	7.40

Source: AEMC 2012k, p. 64.

Sometimes, as is the case in Tasmania and South Australia, the levels of standards are informed by averaging past performance. Other times, they are set at a more demanding level than past performance to encourage businesses to improve reliability. Targets can be static or become more demanding over time, as was the case in New South Wales between 2005-06 to 2010-11, and is currently occurring in Queensland. While ActewAGL and the Office of the Tasmanian Economic Regulator have considered the use of customer values of reliability, neither have explicitly incorporated value of customer reliability estimates into the setting of their standards.

Jurisdiction-specific performance standards are set by a regulator in South Australia, Tasmania and the ACT.⁵ In Queensland the Minister can amend the Code and the regulator can propose amendments subject to stakeholder consultation. In New South Wales the Minister sets the standards.

Businesses in Queensland, South Australia, Tasmania, and Victoria are required to use ‘best’ or ‘reasonable’ endeavours to meet standards. ActewAGL faces penalties for missing targets unless they can provide a ‘reasonable excuse’ and businesses in New South Wales must be as compliant as ‘reasonably practicable’ by 2014 and fully compliant by 2019. Penalties apply in all jurisdictions if businesses contravene

⁵ In the ACT, these are minimum standards and the business can set higher targets.

their reliability requirements and can range from fines of around \$100 000 to revocation of a business's licence (although this has never occurred in the NEM).

Distribution businesses are required to report their performance against their standards, with (potentially) additional reporting in the event of a failure to meet standards. For example, in New South Wales, distribution businesses are required to report their performance against the standards to the Minister quarterly and include reasons for failing to comply with standards. Distribution businesses in New South Wales are also required to provide an independently audited report annually to the Independent Pricing and Regulatory Tribunal (IPART) (AEMC 2011g, p. 18).

Consequences for efficiency

The discussion above highlights that no two jurisdiction-specific reliability performance frameworks are the same. The AEMC (2009b) agreed:

There is a lack of consistency and transparency in how the different jurisdictional standards are determined and described. Also how the distribution businesses interpret and comply with these standards can vary significantly across the NEM. (pp. executive summary)

In this type of regulatory environment, benchmarking distribution businesses is difficult. Reliability settings that vary considerably from one jurisdiction to the next create another factor that is external to the business that would need to be controlled for in any meaningful benchmarking exercise.

Benchmarking the standards themselves, and the frameworks in which they sit, however, is more straightforward, and a number of costs and benefits can be identified.

The benefits of imposing jurisdiction-specific performance standards in addition to the STPIS are not immediately obvious. However, it is possible that jurisdictional authorities see value in retaining the ability to strip a distribution business of its licence in the case of extreme underperformance. It is not clear though, that while retaining the authority to remove a business's licence, why jurisdictional authorities do not align their standards with those in the STPIS, such as is currently done in Victoria. Requiring distribution businesses to adhere to and report their performance against two sets of standards is costly and does not seem to produce obvious benefits. According to Endeavour Energy (2012):

We do however see benefits in aligning national and jurisdictional reporting requirements where duplicate reporting regimes are to be maintained (for example the AER's STPIS and jurisdictional requirements. (p. 3)

Another possible benefit arises from customers ‘feeling closer’ to the standard-setting body, especially if that body is the state government, and therefore feeling that they have more control over the reliability they receive. However, no jurisdiction-specific standards incorporate customer values in their standard setting process. Rather, significant changes to standards by jurisdictional authorities appear to occur in response to political pressure or intervention and publicly expressed customer discontent, which suggests that the ‘closeness’ of the relationship produces, at best, delayed and reactive responses to customer demands. These ‘reactive’ responses could also be disproportionate to the actual value the customers overall place on rectifying the issues in question, and may not be targeted appropriately in any case.

Another inefficiency arises from setting standards using a business’s historical performance. Setting standards without reference to customer values of reliability creates inefficiency. Standards for reliability are only efficient when the value that customers place on the extra reliability is equal to the cost to the business to provide it; otherwise, customers incur unjustified additional costs (chapter 14).

The current AEMC review of distribution reliability seeks to assess whether standards in New South Wales are indeed too high or too low by measuring consumer willingness to pay for improvements in reliability. The report concluded that:

Over a fifteen year timeframe, each of our three scenarios for lower reliability outcomes would provide net benefits and would result in significant reductions in distribution expenditure for reliability. (AEMC 2012l, p. v)

The AER’s service target performance incentive scheme

The STPIS provides incentives for distribution businesses to deliver reliability outcomes to customers. Its purpose is to:

... balance the incentive to reduce expenditure with the need to maintain and improve service quality for customers through establishing a direct financial link (reward or penalty) between revenue and service standards. (AER 2007a, p. 7)

The Rules set out requirements for the AER to establish and publish the STPIS (clause 6.6.2(b)). In carrying out this role, the AER was required to meet a number of criteria including taking into account the willingness of customers to pay for improved performance in the delivery of services, and the need to ensure that incentives are sufficient to offset any incentive the business might have to reduce costs at the expense of service levels.

The STPIS has five components:

1. reliability of supply
2. quality of supply
3. customer service
4. guaranteed service levels
5. information and reporting

All components of the STPIS, except the guaranteed service level component, operate in addition to existing jurisdiction-specific requirements. The guaranteed service level component only applies where no corresponding jurisdiction-specific requirement exists. As a result, it is not currently applied to any distribution business in the NEM.

Reliability of supply

The STPIS sets performance targets according to feeder type for distribution businesses using unplanned SAIDI, unplanned SAIFI, and MAIFI indicators.⁶

The AER sets performance targets for these indicators at the beginning of each regulatory control period during the revenue determination process (table 16.3). The targets are calculated as the average of the available performance data for the five most recent years. The AER then makes adjustments, such as for:

- impacts on past performance from events that are considered to be outside of the control of a distribution business, for example, load shedding due to generation shortfall or failures in transmission networks, or interruptions during extreme weather events (box 16.2)
- any improvements in reliability that are anticipated to result from expenditure that the AER has or will approve in past or current revenue determinations.

Distribution businesses report their performance against their targets annually, and differentiate outages that they believe should be excluded from the calculation of their reward or penalty.

⁶ Some distribution businesses are excluded from meeting MAIFI targets if they can show that they do not have the capabilities to measure and report on momentary interruptions and the costs of installing the required equipment are expected to outweigh the benefits.

Table 16.3 Example targets for STPIS reliability of supply parameters
Ergon Energy

<i>Parameter</i>	<i>Unit</i>	<i>Targets</i>				
		2010-11	2011-12	2012-13	2013-14	2014-15
SAIDI	Minutes					
Urban		129	128	127	127	126
Short rural		296	291	287	283	279
Long rural		699	687	675	664	652
SAIFI	Interruptions					
Urban		1.69	1.68	1.66	1.64	1.63
Short rural		3.06	3.02	2.98	2.94	2.91
Long rural		5.59	5.52	5.44	5.37	5.29

Source: AER (2009c, p. 304).

Some events are excluded from the measurement of performance against targets because, in theory, distribution businesses should not be penalised for interruptions that were not their fault. Excluding certain types of event, however, also weakens the incentives that businesses have to prevent those types of event from recurring. The AEMC gives the example of an interruption caused by a car accident; while the business is not ‘directly responsible’ for the accident, there are measures that it could take to avoid future accidents, such as positioning poles further from roads (albeit at a cost) (AEMC 2012k, p. 32).

These matters illustrate a problem common with many incentive schemes that sometimes they motivate as much ‘internal’ focus on debating and defining the ‘rules and exceptions’ as they do on businesses genuinely looking outwards and trying to achieve the intended objective — in this case improved satisfaction in the eyes of end customers. Apart from the issues around VCR, for some of the other components included in the STPIS, it is not entirely clear whether customers have been adequately consulted for example about whether they care much about the exact reasons for an outage. It is likely that for some, the fact that there is an outage, planned or unplanned, due to an event defined as ‘controllable or uncontrollable’, all they really care about is getting their power supply restored quickly. It is important moving forward that distribution businesses and the AER spend adequate time gathering feedback from end customers about their views in regard to supply interruptions, and that over time the STPIS targets are adjusted to reflect this feedback.

Box 16.2 Major event days — an exclusion from STPIS performance measures

A major event is defined as a catastrophic event that exceeds the capacity of the electricity network to avoid significant power interruptions. Major event days (MED) are calendar days on which a major event occurs – even if the power interruption lasts for several days, only one day is recorded as an MED.

A day with a large unplanned SAIDI can be classified as an MED if the total unplanned SAIDI for that day is unusually high.⁷

The unplanned SAIDI from MEDs are not included in the calculation of how far a business's performance is from its target in a regulatory year. Therefore, there has been some debate about the best way to define a MED, with less stringent definitions leading to more events being excluded (and therefore the appearance of an improved performance by the business against its target).

Similarly, as discussed by SP AusNet (2010, p. 37), setting the definition of a MED too leniently might create perverse incentives for businesses to allow an event with negative consequences for unplanned SAIDI to escalate into a major event (by failing to reconnect power as quickly as possible), such that it 'creates' an MED.

Setting the definition of an MED too stringently might put businesses' revenue at risk from events that are outside of their control. For example, there have been suggestions that raising the threshold would be more appropriate.⁸ Businesses, however, were concerned that many events that were caused by extreme weather events (and therefore outside of the control of businesses) would cause unplanned SAIDI results of less than the MED threshold and consequently put business revenue at risk from not meeting STPIS targets.

Sources: AER (2009d); SP AusNet (2010).

Quality of supply component

There is provision in the STPIS for quality of supply to be measured, however, currently there are no parameters specified.

⁷ That is, where unplanned SAIDI is more than 2.5 standard deviations from the mean of the log normal distribution of five regulatory years' SAIDI data.

⁸ Specifically, proposals called for the threshold to be raised from the current (minimum) 2.5 standard deviations, up to 3.5 standard deviations.

Customer service component

The STPIS includes parameters for customer service that distribution businesses are required to meet, including times for making streetlight repairs, new connections, answering telephone enquiries and responding to written queries.

Distribution businesses that exceed (do not meet) the targets that the AER sets for these parameters can gain (lose) in total a maximum of 1 per cent of their allowed revenue. The targets are usually an average of the performance of the previous five years and are also adjusted for anticipated improvements from customer service related expenditure allowed under past or current revenue determinations.

Guaranteed service levels

The guaranteed service level component of the STPIS is intended to provide an incentive for distribution businesses to acknowledge and address the sub-standard reliability and service outcomes that some customers experience. The parameters covered under this component and the target levels of performance for businesses are contained in table 16.4, along with the payments that businesses would be required to pay, for each instance of performance shortfall.

These payments are not linked to the cost that poor service imposes on customers but are intended to be an acknowledgment of poor service. Payments must be made directly to consumers as soon as a distribution business becomes aware of having missed a target and where it is responsible for that failure.⁹ This is not the case in some jurisdiction-specific guaranteed service level schemes that require customers to apply for payments.

This component of the STPIS is not currently applied in any jurisdiction in the NEM (although it is anticipated to begin in the next regulatory control period for Victoria). Instead, jurisdiction specific schemes containing a wide range of parameters, targets and levels of payments are applied.

⁹ Distribution businesses do not have to make payments when they are not responsible for missing a target (for example, due to transmission failure).

Table 16.4 Guaranteed service level parameters, thresholds and payments in STPIS

subtitle

<i>Parameter</i>	<i>Threshold</i>	<i>Penalty per occurrence (\$)</i>
Frequency of interruptions – CBD and urban feeders	9 interruptions	80
Frequency of interruptions – rural short and long feeders	15 interruptions	80
Duration of interruptions – CBD and urban	12 hours	80
Duration of interruptions – rural short and long feeders	18 hours	80
Total duration of interruptions – level 1	20 hours	100
Total duration of interruptions – level 2	30 hours	150
Total duration of interruptions – level 3	60 hours	300
Streetlight repair	5 days	25
New connections	Connection on or before the agreed day	50 per day (maximum 300)
Notice of planned interruptions	4 days excluding weekend and public holidays	50
Frequency of interruptions – CBD and urban feeders	9 interruptions	80

Source: AER (2009d, p. 18).

Information and reporting requirements

The STPIS requires distribution businesses to report annually against the parameters under the scheme, and stipulate any exclusions that the business believes should be applied. The AER can review the reports to ensure they account for exclusions accurately, calculate the consequences for allowed revenue correctly, and that the data collected match the parameters under the scheme.

Aspects of the reporting requirements, and related information gathering processes appear to lack transparency. For example, the AER issues each business a request for information notice outlining the business specific data that it wants to collect. Any public reporting of this data needs to be approved by the business before it is released and currently, there is no public reporting that is specific to the STPIS.

Nevertheless, STPIS reporting and information requirements mostly exceed, and are in addition to, jurisdiction-specific reporting requirements, with the exception of Victoria. In the latter case, the AER's Annual Performance Report (2012h) for the Victorian distribution businesses details reliability performance at the zone substation level and identifies the main causes of faults in the networks. This reporting structure and detail were inherited by the AER in the transition of responsibilities from the Essential Services Commission of Victoria (ESCV) and

now form the basis of the reporting requirement for Victoria under the STPIS. This report provides a useful benchmark for establishing consistent, transparent and detailed reporting of reliability performance NEM-wide.

Incentives under the STPIS

The first three components of the STPIS have incentives attached to them to encourage the distribution businesses to meet their specific targets. The incentives are based on a VCR and the gap between the performance of the business and the target. The AER calculates the incentive rates using a VCR that is specific for each feeder type. The VCR for a CBD-feeder is \$96 per kWh (indexed to the CPI from September 2008). For all other feeder types, the VCR is \$48 per kWh (AER 2009d, p. 10). In this way, the incentives for businesses to meet their targets are directly related to the costs (benefits) that customers experience when businesses fall short of (exceed) their targets.

The incentives are converted into a share of the annual maximum allowable revenue for a business, termed the ‘s-factor’. The maximum that a business can be rewarded or penalised is termed the ‘revenue at risk’. The default level for each year in a regulatory control period is 5 per cent, though actual levels range from 3 per cent for Ergon Energy in Queensland to 7 per cent for SP AusNet in Victoria. Distributors can apply to postpone the incorporation of the revenue increments or decrements for a year to avoid excessive price fluctuations for customers.

Under the STPIS, a business that meets all its targets gets additional revenue by being allowed by the AER to increase its prices to customers — who effectively pay an additional price for the improved ‘quality’ of the service they receive. Likewise, if a business fails to meet its targets it gets penalised and has to reduce its prices to customers who receive some compensation for the poorer performance. The fact that customers thus end up directly paying for the performance that is incentivised by the STPIS, emphasises the point made earlier about the importance of aligning the STPIS targets with things that customers most value.

Consequences for efficiency

On the one hand, the reporting requirements under the STPIS are likely to facilitate benchmarking of businesses if the information currently collected by the AER is consistent and reasonably detailed. However, it appears there is room for significant strengthening and streamlining of reporting requirements in the STPIS, especially outside of Victoria, and all non-commercially confidential information should be released publically (and there should be an onus of proof on the business to show

why any of this information is commercially confidential — these are regulated monopolies after all).

On the other hand, because the STPIS operates alongside existing jurisdiction-specific reliability standards, not every business is subject to the same parameters of the scheme. This inconsistency adds to the factors that must be controlled for in a benchmarking exercise, making such an exercise more difficult.

The STPIS has many valuable features, including the consistency between the incentives offered and the reliability related revenue approved by the AER. Nonetheless, several concerns remain:

- The targets are based on a business's historical performance. As discussed in the context of jurisdiction-specific standards, historical performance as a basis for a reliability standard does not have regard to customers' willingness to pay.
- The rewards and penalties received under the scheme are unlikely to be providing the right incentives to distribution businesses to encourage them to efficiently meet customer preferences, due to issues in using a single VCR (box 16.3) and the implications of errors (box 16.4). Furthermore, the AER uses the same VCR for all distribution businesses, which ignores the different preferences that customers between, and indeed within, distribution networks might have.
- The default revenue at risk is 5 per cent to avoid 'imposing undue risk' on businesses by making businesses 'accountable for events caused by factors over which [they have] little or no control' (AER 2008b, p. 16, AER 2007a, p. 23). It is not clear, however, from the discussion contained in the documents establishing the STPIS, that 5 per cent revenue at risk provides a large enough incentive to prompt businesses to adjust their reliability performance sufficiently.

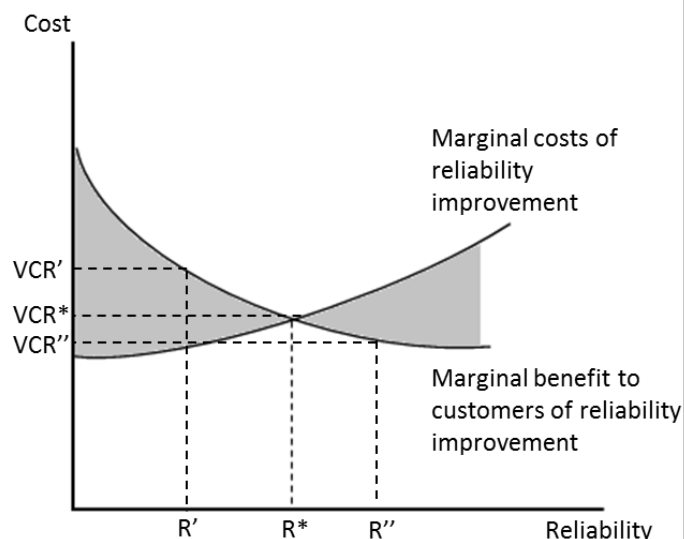
Consumers also incur risk from uncapped revenue at risk in the form of excessive price fluctuations from one year to the next, although the s-bank mechanism in the STPIS helps to smooth volatility in prices over time (AER 2009d, p. 30).

Box 16.3 The problem with a single value of customer reliability

The efficient level of reliability, as discussed in chapter 14, is where the marginal benefit to customers of extra reliability is equal to the marginal cost to the business of supplying it.

Assuming that the targets in the STPIS are set at the efficient level, the optimal incentive to apply to businesses that perform above or below their target is a function of the VCR and the gap between the target and the performance. Theoretically, however, the VCR is not constant, and the incentives should be higher when a business under-performs than when it over-performs.

In the figure below, when a business performs at R' , below its efficient (and target) level of R^* , the optimal penalty should recognise that the cost to customers, VCR' , is higher than the cost to the business of improving reliability. Penalising the business using VCR^* will not be equivalent to the loss that consumers experience for this level of underperformance.



Similarly, if a business exceeds the target at R'' , it will be rewarded using VCR^* when customers only value the increased reliability at VCR'' . This means that businesses are being rewarded by more than the marginal benefit accruing to customers.

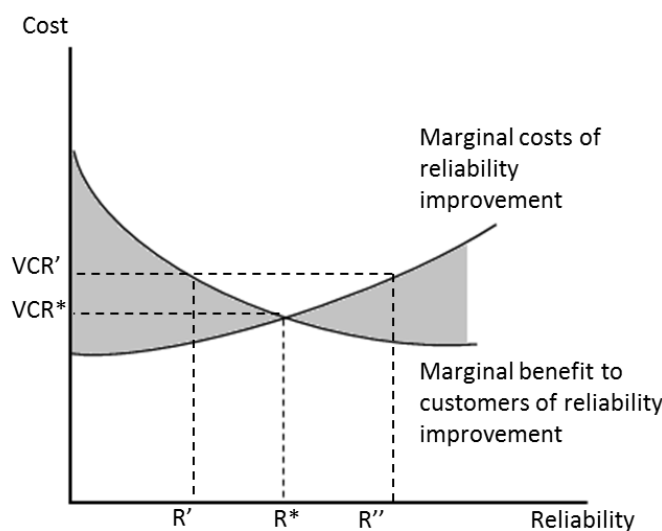
In reality, however, applying variable VCRs that correspond to a marginal benefits curve like that in the figure is challenging, especially considering the difficulties associated with identifying accurate VCRs as discussed in chapter 14.

Box 16.4 What happens if the value of customer reliability and the targets are wrong?

Using the figure below it is possible to examine how incentive schemes can produce inefficient levels of reliability when the VCR and/or the targets are not at their optimal points.

Assume first that the target is set optimally at R^* , but the VCR is set at VCR' . As the business will receive a payment greater than its marginal costs at the point R^* , it will have an incentive to supply reliability up to the point R'' . This point is not optimal for customers, and inefficiencies are generated.

Assume instead, that that target is set incorrectly at point R'' , but the VCR for the incentives is the correct VCR^* . Businesses will have the incentive to supply reliability only up to point R^* but not beyond. Beyond R^* , the costs to the business are larger than the penalties they will incur for failing to meet the targets.



These examples suggest that in theory as long as the VCR is set at an appropriate level, businesses will tend towards supplying a level of reliability that reflects customer preferences, regardless of the target set.

16.4 An efficient and effective distribution reliability framework — a bolstered STPIS

The discussion of the current reliability frameworks in the NEM suggest there are opportunities for efficiency gains to be realised, both in terms of encouraging

managerial efficiency by facilitating benchmarking, and also by reducing inefficiencies in reliability standards and the frameworks in which they operate.

Removing input standards

An efficient reliability framework will set reliability targets at levels that reflect customer preferences, and encourage distribution businesses to pursue those targets through the best combination of building, maintaining and managing their networks and responding to outages. To some extent, these inputs can be substituted. Imposing restrictions on the way that businesses choose the mix of inputs, such as through imposing deterministic standards, increases costs. According to the Brattle Group (2012a):

... rigid planning standards could be counter-productive because they can prevent distributors implementing innovative approaches to improving reliability. (p. 160)

Costs can also be imposed on a network business by requiring that they plan using a probabilistic process. While probabilistic planning is likely to lead to cost effective augmentation decisions, it may not be the most appropriate planning tool for all businesses, for all investments, all the time. Distribution businesses should therefore be free to choose the way that they plan.¹⁰ Jemena (2012) submitted that:

... the adoption of probabilistic planning for our network has improved reliability and cost outcomes and in our case has provided a superior alternative approach to deterministic planning. That said, we believe the [distribution businesses] should be allowed to decide the most suitable approach to network reliability planning having regard to local network characteristics or geographic conditions. (p. 3)

Energex (2012) agreed:

... planning standards should be the responsibility of [distribution businesses]. Regulators and/or governments should not be involved in determining the design planning criteria as [distribution businesses] are the parties that are best placed to perform this function. (p. 2)

How much is this change worth?

The possible benefits of removing planning standards for distribution businesses are not to be underestimated. As an example, AEMO calculated the cost savings of removing the deterministic standards that apply to Ausgrid. Using a probabilistic

¹⁰ While this arm's length approach is appropriate for distribution businesses, which can be encouraged to deliver reliability through the use of incentives, it is not appropriate for transmission networks where transmission specific characteristics (box 15.3) require a more 'hands on' approach to NEM-wide transmission planning.

process, AEMO found that one proposed substation could be safely deferred for up to ten years. In total, AEMO identified \$1.1 billion in augmentation capex that could be deferred until the next regulatory period. For the average customer, this would equate to a saving of around \$50 per year from their electricity bill from 2014 onwards.

Smaller gains were identified by the AEMC (2012l) in their current review of distribution reliability outcomes in New South Wales. The ‘extreme’ reduction in reliability outcomes scenario in New South Wales identified a possible saving of \$15 a year for residential customers that could be expected to be realised from 2028. Several points might help explain these smaller results:

- The reliability reductions that were modelled might not have been very ‘extreme’.¹¹ For example, Public Interest Advocacy Centre (PIAC) was ‘surprised by the very modest reductions in customer reliability ... that occur under the three scenarios modelled by the AEMC’ (2012, p. 4).
- The capital requirements to meet existing deterministic standards into the future have already been built, leaving few investments to be deferred, and resulting in lower expected benefits (AEMC 2012l, p. 129).
- The distribution businesses might have been unable to identify all the areas in which efficiencies could be realised given the ‘simplifying assumptions’ they made to prepare the data for the report in a ‘relatively short timeframe’ (AEMC 2012l, p. 26).

The total change in capital expenditure in the ‘extreme’ scenario was projected to be \$1.1 billion over the next 15 years (net present value), which would equate to an annual saving of around 4 per cent of the forecast capital expenditure in New South Wales in 2012-13.

In reality, the effect of removing planning standards for distribution businesses is likely to result in larger benefits than those that have been estimated and described above. Combining the flexibility of choosing exactly how to meet target levels of reliability (by removing any bias towards capital expenditure) with incentives to meet standards efficiently (and removing the incentive to over-invest — chapter 5) should result in larger savings for customers NEM-wide. Further, as demand increases, and the current redundancy built into the network diminishes, the value of deferring new investments efficiently will produce higher savings to customers in the long-run.

¹¹ The ‘extreme’ scenario was expected to result in 15 more minutes of outage a year. IPART (2012d) suggested the AEMC use more objective descriptors for the scenarios (p. 3).

Bolstering the STPIS

Removing *planning* standards altogether would increase the need for *performance* standards (the output measure) to be set efficiently, and supported by strong incentives to encourage businesses to achieve standards of reliability that customers are willing to pay for.

Establishing a national framework

Requiring distribution businesses to adhere to more than one set of performance standards increases the risk of businesses inefficiently delivering reliability outcomes below (or above) the level that customers are willing to pay for. The AEMC (2012k) also points to possible unclear or inconsistent incentives from ‘duplication between jurisdictional requirements and the requirements of the STPIS’ (p. 41).

In the Commission’s view, removing jurisdiction-specific performance standards and relying on the STPIS is likely to be the most efficient option for the NEM.

The Commission notes that the third option for a national framework for distribution reliability outcomes identified by the AEMC (2012k) recommends removing ‘some of the existing jurisdictional requirements that may no longer be needed once the STPIS is in place’ (p. 41). This option is (notionally) widely supported by participants in the review, including CitiPower and Powercor, SP AusNet, Essential Energy, Major Energy Users Inc. and Jemena (Energex supports a national framework, and Endeavour Energy proposes a larger role for the AER).

Retaining even some reliability requirements in jurisdictional codes and licence conditions, however, inefficiently adds to costs for distribution businesses:

- the costs of ‘unclear or inconsistent incentives’ discussed above are maintained
- new costs are introduced from the uncertainty for distribution businesses from state and territory governments and regulators having the authority to introduce or change reliability requirements at will
 - for example, as a result of the politicisation of reliability outcomes, the potential for which was identified by the Brattle Group (2012a, p. 28).

All reliability requirements should therefore be removed from distribution business licence conditions and jurisdictional codes and regulations. This would require the Standing Council on Energy and Resources (SCER) to effectively transfer the responsibility of setting a reliability performance framework to the national level,

through an amendment of the Australian Energy Market Agreement as well as introduce legislative amendments, and agree that the STPIS becomes the only vehicle for delivering reliability outcomes to customers. Under this framework, reliability targets would be set by the AER using business specific average past performance, and rewards and penalties would be set using customer preferences specific to the region in which the business operates.

Harmonising parameters

Removing duplicative jurisdiction-specific reliability requirements, but at the same time ensuring that an incentive scheme is as effective as possible, requires that all parameters of the components in the STPIS are applied to all network businesses.

The Commission recognises that some businesses might not currently be able to record and report on all parameters, such as for example, MAIFI performance. In these instances, the AER should approve the revenue required for the businesses to install the additional equipment needed, subject to the business showing that it has not had the revenue or opportunity to do so previously, and the AER is satisfied that the long term benefits of applying the parameter outweigh the costs of the required investment.

Addressing worst served customers

Participants in the AEMC's review commonly identified the lack of provisions in the STPIS to address the experience of worst served customers. According to Essential Energy (2012):

[T]he STPIS, as currently structured, will encourage [distribution businesses] to focus reliability improvements on parts of the network in urban areas that may already be performing quite well at the expense of poorly performing parts of the network in rural areas. (p. 2)

Essential Energy recommended that the AER establish minimum service standards such as already exist in New South Wales. The Brattle Group (2012a), however, while recommending supplementary mechanisms relating to worst served customers, believed a requirement to publish annual distribution planning statements was more appropriate than establishing financial incentives attached to targets specifically designed for worst performing feeders.

The Commission concurs that publicly reporting performance (and possibly planning) is likely to encourage an improvement in the performance of worst performing feeders, provided distribution businesses are responsive to public pressure and reputational consequences. Furthermore, licence conditions that

require businesses to supply connected customers, and develop contingency plans for how to deal with outages are likely to help ensure that at least minimum acceptable levels of service are met.

For individual customers, poor service is recognised by distribution businesses through the payments for guaranteed service levels. While these payments are not intended to be compensation for poor reliability, their reporting, especially at a disaggregated level, is likely to increase awareness of areas where distribution businesses are failing to provide reliable supply. Importantly though, it should be recognised that the goal is not to pursue uniformly high reliability across all parts of Australia. As discussed in chapter 14, the much higher cost of improving reliability in parts of the NEM — and especially in more remote areas — means that differences in reliability levels are both inevitable and efficient.

To support more disaggregated reporting of reliability for worst served customers, the relevant reporting requirements under the STPIS should be amended to reflect the level of detail and consistency currently contained in the Victorian Annual Performance Reports. Where distribution businesses are unable to collect the information required to report to the AER in that detail, the AER should approve efficient expenditure required to upgrade recording and reporting equipment.

Setting efficient targets

The reliability performance targets in the STPIS, based on historical performance, are unlikely to be efficient. The conceptual requirement to set reliability standards at a level where the incremental costs and benefits of further improvements are aligned cannot reasonably be disputed. But the hard part is performing that calculus in an imperfect real world.

One issue here is that businesses are likely to know their marginal cost functions but regulators are not, at least not without significant increases in information and data from businesses. While methodology exists for estimating the marginal cost curves for distribution businesses in the NEM,¹² it is not apparent that robust estimates would be available for use in setting reliability targets in the near future, especially at a disaggregated level.

So how should efficient targets be set? The key lies not in the targets themselves, but in the incentives (or penalties) that apply for divergence from target levels, which are based on an appropriate VCR.

¹² For example, Jamasb et al. 2010 estimate marginal cost curves for UK electricity distribution companies at an aggregate level.

Applying the right incentives (in terms of rewards and penalties to businesses) over time can encourage businesses to adjust their reliability levels to reflect the levels that customers prefer even if only one value of VCR is used (box 16.3) and the initial targets are incorrect (box 16.4). Box 16.5 sets out a means for progressively iterating the current historical performance targets towards this goal.

To motivate this adjustment the AER should issue the performance targets for businesses annually using a moving five year average of past performance.

The difficulty still remains, however, of ensuring that the VCR used to calculate the penalties and rewards is set at the right level to reflect the preferences of customers of each distribution business.

Were the Australian Bureau of Statistics to conduct regular surveys of customers as recommended by the Commission (draft recommendation 14.1), it would be able to identify a VCR corresponding to the level of reliability that customers have recently experienced. If the incentives for distribution businesses are then based on this VCR, it will be possible to tell if the business has been performing below (or above) the efficient level by the way that the business responds to the incentives. If the business responds by improving performance, then the target will eventually shift up and the VCR (after new surveys have been conducted) should shift down.

Therefore, while a moving historical average can ensure targets for a business converge to an efficient level, so too must the VCRs used for calculating incentives also be re-estimated regularly. In this way, over time, reliability targets and incentive rates should move toward levels that encourage businesses to find least costs ways to provide the level of reliability preferred by customers.

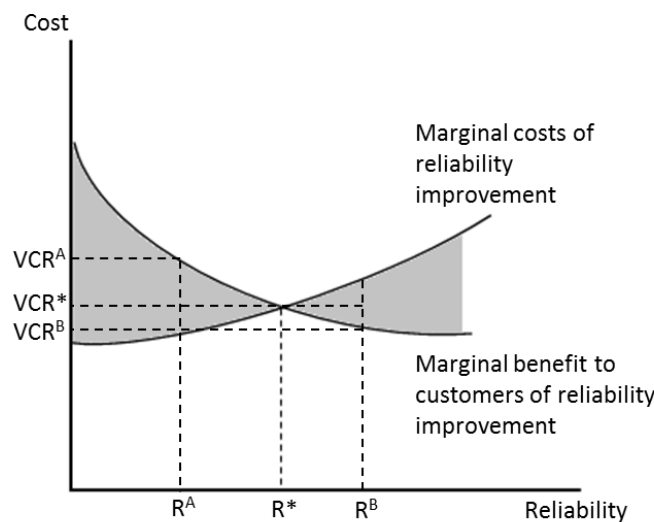
Compared to current processes, these changes are not a significant shift for the AER or distribution businesses already operating under the Scheme, however, they do ensure that reliability targets and the incentives to meet them are firmly planted within a cost-benefit framework. In short, the Commission proposes that:

- performance targets be set using a rolling five year average of past performance
- the incentives be business specific (or more disaggregated) and based on the VCRs estimated by the ABS as recommended in draft recommendation 14.1.

Box 16.5 Adjusting to efficient targets and incentives

The figure below shows the efficient level of reliability at R^* . If the business supplies reliability at R^A instead of R^* , and VCR^* is used to calculate the penalty, the penalty would be larger than the marginal costs to the business of increasing reliability. The business will therefore have an incentive to increase reliability up to R^* .

Similarly, if the business performs at R^B , the reward it receives will be less than the cost of providing the reliability, and reliability will adjust back over time to R^* . This means that so long as rewards and penalties are based on VCR^* (that is, the VCR corresponding to the efficient level of reliability), reliability performance will converge to R^* . As the targets adjust using the moving average of historical performance, the targets also will eventually adjust to R^* .



Identifying VCR^* , however, is not necessarily straightforward. If, for example, a distribution business has consistently been performing at R^A , below efficient levels, the surveys of customer values of reliability might identify a VCR greater than VCR^* (VCR^A in the figure) reflecting recently experienced levels of reliability. If incentives are then based on this higher VCR, the business would have an incentive to increase performance past the efficient point.

This would also apply for a distribution business performing consistently above R^* (R^B in the figure), leading to incentives based on an identified VCR below VCR^* . The business would have an incentive to reduce performance below R^* and the targets would eventually adjust to reflect this. In response to these changes in reliability, however, customers will adjust the value they place on more reliability. By taking regular surveys to identify these values and incorporating the updated values into the incentives, the reliability performance should slowly adjust towards its efficient level.

Ensuring incentives are strong

The transition path to efficient reliability targets will be slower if the incentives that distribution businesses respond to are capped. The Brattle Group (2012a) noted that:

We also found that ... distributors with the most to lose (i.e. facing the highest potential penalties) tend to comply more closely with reliability standards than those facing less punitive sanctions, at least as regards the average duration of interruptions. (p. 11)

As revealed in the discussion above, incentives should also be two sided — that is, businesses should incur penalties for under performance and rewards for exceeding performance targets. The Brattle Group (2012a) contended that this avoids a ‘cliff edge’ effect:

... whereby distributors will be reluctant to invest to improve reliability when they are close to their target if this could lead to higher than target reliability for which they will not be rewarded. (p. 14)

There is a mix of opinions regarding how incentives should be set for distribution businesses. Some businesses, for example SP AusNet, preferred uncapped two-sided incentives. In response however, the Energy Users Coalition of Victoria (EUCV 2010) noted that there is already an implicit floor in the penalty that the AER can apply, because removing too much revenue from a business will ultimately result in a loss of supply of electricity to SP AusNet customers. This would make the incentives ‘asymmetric’ (p. 45).

There is also a concern that because rewards and penalties affect the prices that customers pay, large incentives can lead to excessive fluctuations in price for customers (AER 2010b, p. 674).

Similarly, point targets for businesses can introduce uncertainty if small changes in performance can tip a business over the line from receiving a reward to having to pay a penalty and vice versa. To address this, some commentators discuss the possibility of using ‘dead bands’ — that is, having a target range for businesses rather than a point (for example Yahav et al. 2008 and Ramanathan et al. 2006). However, as small variations from performance targets result in small rewards and penalties, it seems reasonable to suggest that across a five year regulatory period, small deviations from targets year to year should even out.

An advantage of ensuring incentives are sufficiently strong is that it encourages businesses to more efficiently use their choice of inputs into achieving reliability over time. This means that while operational inputs can be used to meet performance targets in a given year (such as responding quickly when faults occur), longer-term investments in network capacity should also be made when they are needed, and it is cost effective to do so. The likelihood of large future penalties for

poor performance from inefficiently deferring investment should create the incentive for businesses to make efficient decisions about their choice of inputs over both the short term and the long term.

While the default for incentive of 5 per cent under the STPIS should therefore remain, the revenue at risk that each business faces should be negotiated with the AER during the revenue determination process, leaving room for the AER and the business to negotiate away from the default where this would be appropriate. In this way, the AER can use all the information available to it more effectively, including the past responsiveness of the business to incentives, the revenue granted for improvements to reliability and the specific characteristics of a network that might make fluctuations in performance more common (for example, inclement weather that results in more events that are nearly classified as ‘major events’).

DRAFT RECOMMENDATION 16.1

The Standing Council on Energy and Resources should specify that reliability requirements for distribution businesses be included in the Australian Energy Regulator’s Service Target Performance Incentive Scheme, replacing all existing jurisdiction-specific reliability settings.

- ***The reliability requirements should reflect the preferences of customers by using the estimated values of customer reliability, as spelt out in draft recommendation 14.1, and should be specific to the distribution business.***

DRAFT RECOMMENDATION 16.2

The Australian Energy Regulator should also make the following amendments to the Service Target Performance Incentive Scheme:

- ***reliability performance targets for the system average interruption duration index, system average interruption frequency index and momentary average interruption frequency index should be adjusted annually, according to rolling five-year average annual performance***
- ***revenue at risk should be negotiated as part of the Australian Energy Regulator’s revenue determination process***
- ***the reporting and information component of this scheme should require distribution businesses to report their reliability performance at the zone substation level. Worst performing feeders should be identified as part of this process***
- ***reporting by all distribution businesses of performance against the parameters in the scheme should be published annually and be at least as detailed and comprehensive as current reporting mechanisms for distribution businesses in Victoria.***

Where a distribution business can show that they are unable to technically comply with one or more parameters of the Service Target Performance Incentive Scheme, and where satisfied that the benefits exceed the costs, the Australian Energy Regulator should:

- *approve the required revenue for the distribution business to install the necessary equipment*
- *require compliance as soon as possible.*

17 The role of interconnectors

Key points

- Interconnectors are a notional concept of connection between regions, regulated for the market dispatch arrangements of the National Electricity Market (NEM). Physically, they are usually a collection of transmission lines which cross the border from one region to another.
- The legacy of the state-based regions of the NEM means that interconnectors are an essential prerequisite for a national electricity market. There are six interconnectors linking the regions in the NEM.
- By allowing inter-regional trade in electricity, interconnectors potentially increase competition in generation, improve the financial markets that address risk for parties in the electricity system, and promote greater security of supply.
 - Problems in the regulatory arrangements for interconnectors can therefore have far-reaching consequences.
- While interconnectors are underpinned ultimately by some physical transmission infrastructure spanning regions:
 - the capacity of any given interconnector sets an upper limit on the amount of power that it can transfer between regions. And there can be other factors which further limit how much power flows in practice. It is the latter degree of actual ‘*interconnection*’ that is policy relevant
 - the capacity of, and congestion on, intra-regional transmission lines, and regulation surrounding the electricity market are important factors that can affect the degree of interconnection.
- Some claim that interconnectors are congested, limiting their potential to enhance the efficiency of the NEM.
 - However, investment in interconnectors involves significant costs, so that the efficient level of congestion is not zero.
- Evidence suggests that, given the existing network and demand profile, the current *physical capacity* of interconnectors is reasonably appropriate.
- Underutilisation, especially in South Australia, and increasing price differentials between regions warrant further investigation.

The terms of reference for this inquiry ask the Commission to ‘examine whether the regulatory regime, with respect to the delivery of interconnector investment in the National Electricity Market (NEM), is delivering economically efficient outcomes’.

Interconnectors can provide several benefits arising from the ability to trade power between regions. As with other transmission lines, they are expensive to build. Nonetheless, in contrast to broader concerns of excessive network investment, there have been concerns about *under*-investment in interconnectors.

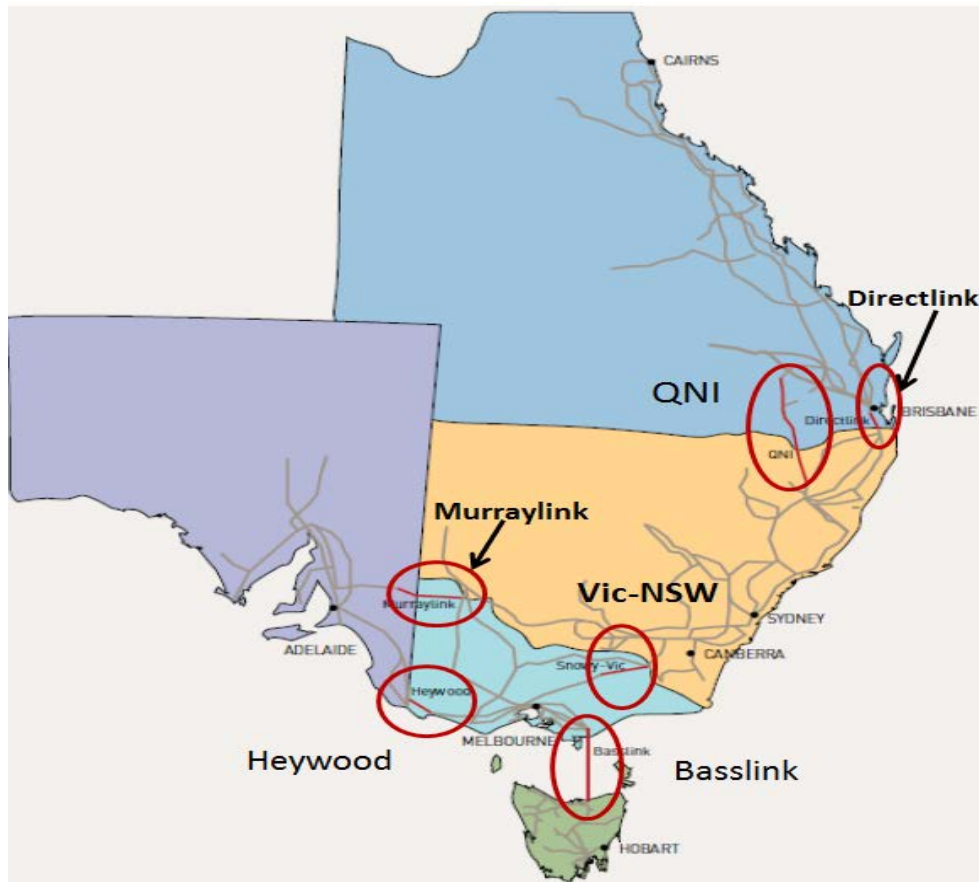
This chapter explores the potential benefits of interconnectors in the NEM, and the extent to which those benefits are being realised in practice.

17.1 Background and perceived problems

Until recently, electricity markets in Australia were characterised by vertically integrated government-owned businesses in each state and territory. Over time, the markets in eastern Australia were linked to form the NEM. The NEM was created as a wholesale market for electricity in the mainland eastern jurisdictions in 1998, with Tasmania joining in 2005 with the completion of Basslink (AEMO 2010f). The interconnectors in the NEM facilitate the trade between the regions (effectively, the states), by allowing power to flow from lower-priced to higher-priced regions. Trade can only occur up to the capacity of the interconnector, after which local generation must meet demand in the higher-priced region. (Also, complications in market design, such as disorderly bidding by generators, discussed in chapter 18 can change the level and direction of flow.)

There are six interconnectors between the jurisdictions in the NEM (figure 17.1). Of these, three interconnectors (Basslink, Murraylink and Directlink) began as ‘merchant’ projects and are discussed further in chapter 20.

Figure 17.1 Interconnectors in the National Electricity Market

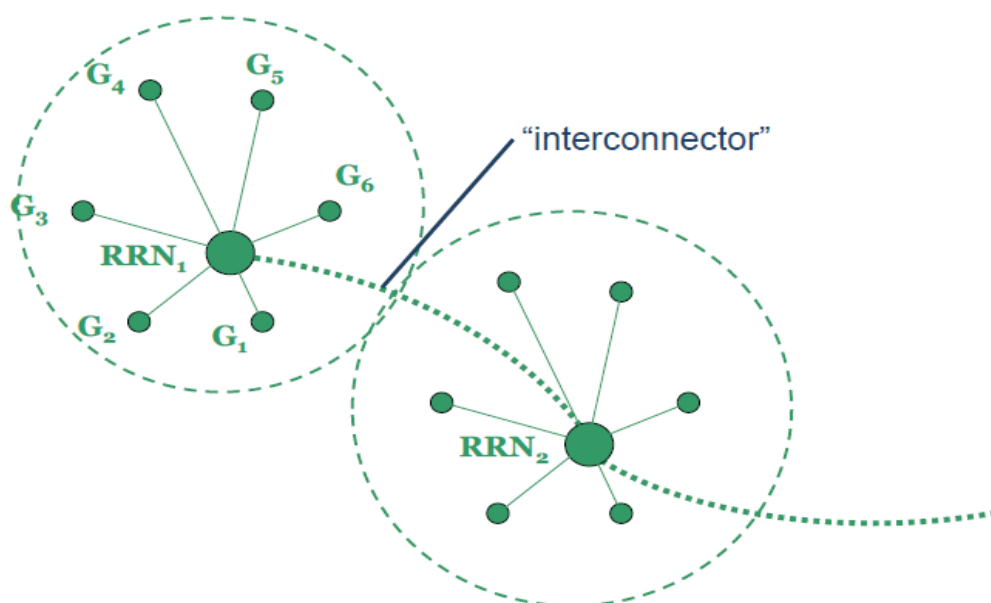


Source: AER 2009

Interconnectors, interconnection and transmission

It is common to refer to interconnectors as just single transmission wires spanning regions and this is how maps of the NEM depict them (figures 17.1 and 17.2). However, referring to such ‘notional’ interconnectors is an abstraction from how interconnectors work. In fact, an interconnector can be composed of several lines — of varying capacity and location — linking generation and load centres (figure 17.3).

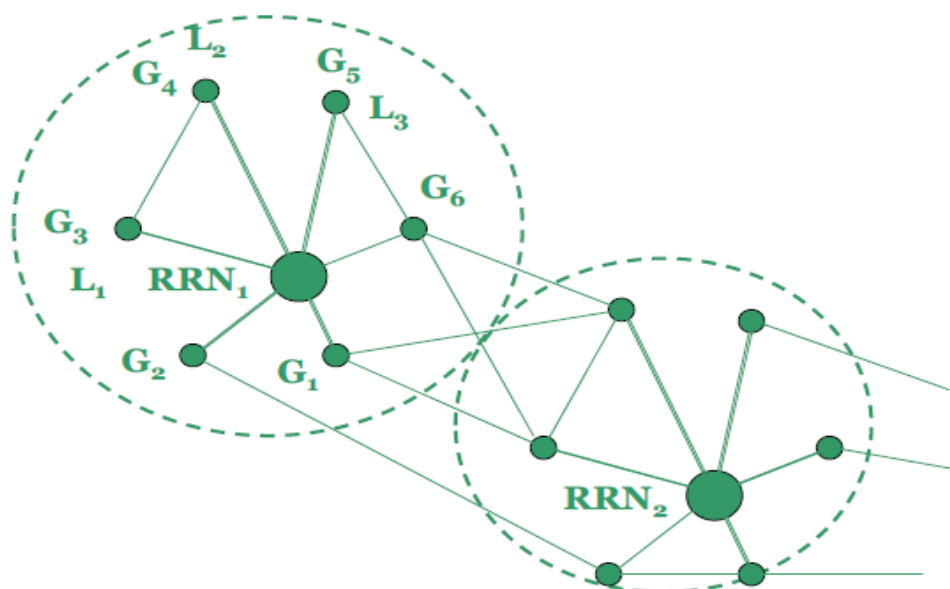
Figure 17.2 Dispatch model representation of a notional interconnector^a



^a 'G' represents generators, 'RRN' represents the regional reference node.

Source: AEMO, sub. 32.

Figure 17.3 Physical interconnection between regions^a



^a 'G' represents generators, 'RRN' represents the regional reference node and 'L' represents load (demand centres)

Source: AEMO, sub. 32.

The complexity of physical electricity networks has important policy implications. When electricity networks are linked, the capacity of one line can be heavily influenced by the capacity of lines connected to it. In effect, the maximum amount of power an interconnector can transport is irrelevant if the capacity of the lines ‘behind’ the interconnector at any given time is lower. For example, if an interconnector has a capacity of 200 MW, but constraints within the regions mean that only 100 MW can reach the interconnector, then the binding factor that determines the amount of power that can be traded is the 100 MW constraint.

Further, the operation of Kirchhoff’s law¹ in an AC network (like the NEM) means that a constraint on any given line will likely have some impact on a number of other lines (not just a directly connected line), particularly in areas where the network is meshed (rather than radial).²

Accordingly, while the ‘capacity’ of individual interconnectors can generally be identified (table 17.1), these figures refer to the capacity of the interconnectors themselves,³ ignoring any constraints behind the interconnectors.⁴ In the day-to-day operation of the system, built capacity, congestion and faults on other lines, as well as the location and behaviour of generators, and the weather can limit the degree of *interconnection* (that is the amount of power that can be transferred between regions) to below the listed levels. As the Australian Energy Market Commission (AEMC) noted in the Transmission Frameworks Review interim report, this degree of network linkage highlights:

... the difficulty of considering intra-regional investments in isolation, since a very large proportion of all transmission investment with a mitigating impact on network constraints will have some inter-regional effect. This is illustrated by recent analysis

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- ¹ Which states that ‘if parallel paths exist in an AC electricity network, the total flow between A and B will be distributed among the parallel paths from A to B in inverse proportion to the resistance along those paths’ (Pollitt 2011, p. 9). In effect, if there are multiple paths for electricity to travel along between two points, then the electricity will take all the paths (in differing shares), rather than any single path. This increases the likelihood that congestion on any one line will affect other lines in the network.
 - ² *Radial* networks are characterised by power travelling in one direction from supply to load along a large ‘trunk’ line, with lower voltage lines branching out from the central line. *Meshed* networks contain additional lines, creating a ‘web’ of several different routes, so that power can travel between any two points, forming some loops within the system (von Meier 2006, p. 150).
 - ³ That is, the amount of power that can be transferred on interconnector infrastructure before that interconnector is constrained.
 - ⁴ The capacity of DC interconnectors (such as Basslink) in an AC system can be more easily determined, as power must be converted from, and back to, AC in order to travel along the DC link. As the amount of power that needs to be converted is known, and controlled, it is simpler to determine the amount that flows along the DC component of the line.

performed for the [AEMC], which found that approximately two-thirds of all constraint equations contain an inter-regional term. (AEMC 2011f, p. 136)

A particular example of this is the Victoria–New South Wales notional interconnector, where the capacity of the ‘wires across the border’ is rarely the limiting factor. The limit is instead set by network constraints within Victoria and New South Wales, particularly around Yass (AEMO 2012f, p. 6), as well as the dispatch (or loss) of large generation units on either side of the border. Given that these other factors regularly determine flows between Victoria and New South Wales, it is difficult to ascribe a single capacity limit to the ‘interconnector’ itself. Although the Australian Energy Market Operator’s (AEMO) settlement residue auction process has nominated 1500 MW as the ‘northerly’ limit for the interconnector, this is purely for financial and not physical reasons.⁵ Nonetheless, the figures in table 17.1 still provide useful predictors of observed flows. For example, during the week of 30 January 2011, when temperatures in Sydney were over 40°C, the flow on the interconnector was recorded as approaching, and in two instances, marginally exceeding, 1500 MW (AEMO 2011d, pp. 45).

Table 17.1 Interconnector capacity in the National Electricity Market
MW

<i>Interconnector</i>	<i>Direction</i>	<i>Technology</i>	<i>Capacity</i>	<i>Peak observed flows^b</i>
QNI	(Qld to NSW)	AC	1078	1060
	(NSW to Qld)	AC	700	20
Directlink		DC	200	207
Vic-NSW	(Vic to NSW)	AC	undefined ^a	1575
	(NSW to Vic)	AC	undefined ^a	489
Basslink	(Tas to Vic)	DC	600	594
	(Vic to Tas)	DC	480	416
Heywood	(both)	AC	460	460
Murraylink		DC	220	213

^a As noted in the text, interconnectors do not have capacities as such. Instead their flows are bound by a number of constraints that vary with conditions applicable at the time. The values listed above are close to the highest flows achievable in ideal network and dispatch conditions, although constraints at lower flows are common. The New South Wales to Victoria (north and south) constraints are particularly difficult to estimate. Some sources (incorrectly) apply a value for this interconnector of 1500 MW (north) and 1300 MW (south), but this value is derived solely from the number of units sold in the Settlement Residue Auction, rather than reflecting the physical aspects of interconnections (AEMO pers. comm., 2 August 2012). ^b These figures reflect flows (in five minute dispatch intervals) in the week beginning 30 January 2011, when temperatures exceed 40°C in Sydney and Adelaide, and 39°C in Melbourne. Such conditions are typically associated with peak levels of power demand. The observed flows also reflect relativities of demand as they are likely to be higher into the ‘importing’ states, such as South Australia and New South Wales.

Sources: AEMO (2012f, 2011d and pers. comm., 3 August 2012); Powerlink and Transgrid (2012).

⁵ Settlement residue auctions are described in chapter 18.

In policy terms, any concerns about the adequacy of investment in interconnectors must also take account of the adequacy of the transmission network as a whole. Several participants pointed out this inseparability:

... as the capacity of an interconnector is a function of both the capacity of the interconnector assets themselves as well as the capacity of the intrastate networks, separating off interconnectors is unlikely to be feasible. (Grid Australia, sub. 22, p. 19)

Interconnectors are notional concepts required for market dispatch and settlement. In a network planning context, an interconnector is indefinable. It cannot be distinguished from others parts of the transmission network. (AEMO, sub. 32, p. 30)

... it is impossible to separate inter- and intra-regional planning, and an emerging conclusion of the [transmission frameworks review] is that greater (rather than less) coordination and optimisation of these activities is desirable. (AEMC, sub. 16, p. 8)

In this context, the key issue is thus the overall scope to achieve economically valuable trading of power between regions, rather than the physical capacity of individual interconnectors. As well as its direct effects on regional electricity prices, the amount of power that can be transferred between regions can enhance:

- allocative efficiency — as consumption decisions respond to price levels
- productive efficiency — interconnection can allow demand centres to access the cheapest generation
- dynamic efficiency — a well interconnected NEM will allow optimisation of investment in generation and transmission over time across the NEM, rather than within individual regions
- security of supply — for example, the existence of the Basslink interconnector apparently avoided costly blackouts in Victoria during the June 2012 earthquake (with the required power flowing from Tasmanian hydropower to Victoria), and provided Tasmania with supply security from Victorian generation when drought conditions limited hydro generation in Tasmania. As discussed in chapters 14 to 16, unreliable supply can be highly costly.

The inseparability of interconnectors from transmission within regions in turn means the current regulatory regime applying to intra-regional transmission is critical to efficient outcomes in regard to interconnectors. Similarly, the location and bidding behaviour of generators can affect the use of interconnectors, raising another set of policy issues. As the AEMC noted:

Due to the complex nature of the transmission system, the AEMC is of the view that it would be insufficient to consider what improvements could be made to the regulatory arrangements for interconnectors in isolation. The regulatory arrangements for all elements of the transmission system within the NEM should be considered in a holistic manner. (sub. 16, p. 7)

Indeed, focusing solely on the interconnectors and ignoring other fundamental policy issues, would produce inferior and potentially even adverse outcomes for the network, electricity consumers, and the community as a whole. Hence, in coming to a view on whether additional investment in interconnectors is a priority, or even required, it is important to be clear about the problem that such investment is intended to resolve.

It is in this policy context that the Commission has considered concerns relating to interconnection in the NEM.

Concerns about interconnection in the National Electricity Market

For some time, some stakeholders have raised concerns about potential under-investment in interconnectors in the NEM. As part of his 2008 review, Garnaut suggested that, in future, interconnectors would need to allow the national integration of generators that locate in jurisdictions that have favourable low-carbon energy sources (such as areas of high, constant wind):

Without a network of interconnectors with enough capacity to cope with the potentially large shifts in interstate flows of electricity over time, much of the generation capacity must remain within a region, even if there are more economic sources elsewhere. Confidence in the capacity of a national system will be particularly important for the period of transition. Interconnector constraints will be reflected in unnecessarily high, and more regionally differentiated and volatile, energy and emissions permit prices. (Garnaut 2008, pp. 446–7)

Garnaut (2011b, p. 30) reiterated his concern about strong biases against inter-state flows in the 2011 update to the review. Previous reviews have also identified issues with interconnection (Parer 2002, p. 128). The International Energy Agency identified ‘de-coupling of prices’ in adjoining states as an indicator of an emerging problem. In particular, it noted that:

The planning system for new transmission lines is not as transparent as the rest of the market... The [then] new rules should not just consider interregional constraints but also the impact of any intraregional constraints, which can manifest themselves as border connection issues in such a long and “stringy” transmission system as Australia’s. (IEA 2005, p. 117)

Others have also identified existing regulatory and planning frameworks as inimical to adequate long-run interconnection (such as the South Australian Department of Transport, Energy and Infrastructure; and International Power in their comments to the current AEMC Transmission Frameworks Review).

But not all agree. Grid Australia noted there are several measures ‘designed to ensure that projects with net market benefits will be identified, evaluated and constructed ... [and] highlighted that all interconnectors are currently undergoing some form of assessment’ (AEMC 2011f, p. 41).

In 2007, the Energy Reform Implementation Group (ERIG) observed that the level of interconnection had ‘increased significantly between the state grids over the past five years’ (ERIG 2007, p. 168), and came to the view that, overall:

... the current level of transmission and interconnection investment is reasonably appropriate for the installed generation capacity and peak demand. However, failure to ensure efficient investment in generation and transmission on a system wide basis into the future puts at risk the efficiency gains achieved as a result of previous energy market reforms. (ERIG 2007, p. 145)

In its 2008 Congestion Management Review, the AEMC concluded that congestion in the NEM was ‘unpredictable’ and typically only caused mis-pricing for short periods before additional transmission or generation investment resolved the issue:

Overall, with the exception of the Snowy region, congestion did not appear to be a major problem in the NEM. (AEMC 2008b, p. 13)

However, the AEMC went on to note that in relation to interconnectors there had been:

... an increase in the total hours of binding constraints on interconnectors since NEM start. Hours rose steeply from 2139 hours in 1998/99 to 9925 hours in 2000/01. This was followed by a sharp fall to 2398 hours in 2001/02, which was caused by a reduction in outages hours binding on the Queensland-to- NSW interconnector (QNI) of 6400 hours. Since then there has been a steady rise from 6781 hours in 2002/03 to 12 849 hours in 2006/07 (or 8242 hours excluding Tasmania). (AEMC 2008b, p. 72)

The debate has not moved on much — in this inquiry, participants put forward similarly divergent views about the adequacy of current interconnection and the ability of the regulatory framework to deliver efficient levels of interconnection into the future.

Some, such as AEMO, argued that the current regulatory (and planning) framework could not deliver a truly ‘national’ system:

... the manner in which assessments for [transmission] investment are undertaken, the analysis, public consultation and transparency of decisions is questionable.

There are many examples of the state-by-state approach to transmission planning which inhibits the development of a national grid. (sub. 32, p. 31)

Similarly, while the Australian Energy Regulator (AER) considered ‘there are signs the framework is providing increased incentives to review the level of transmission

interconnection between regions’ (sub. 13, p. 25), it also noted concerns that the framework could ‘promote reliability-driven region-centric’ investment (sub. 13, p. 28).

On the other hand, the AEMC submitted that there is little evidence of any material problem:

It is not immediately obvious that the level of price separation between regions within the NEM would suggest that there is a clearly insufficient level of interregional transmission capacity between the regions. While the absence of significant and sustained price separation between regions is not necessarily determinative of sufficient inter-regional investment, we consider that it provides a useful indicator.

While it is not clear to the [AEMC] that the current arrangements are failing to deliver an efficient level of inter-regional investment or that options for additional inter-regional investment are not being considered by [transmission network service providers], this is not to say that there is no scope for enhancing transmission planning arrangements in the NEM. (sub. 16, p. 7)

Grid Australia reiterated its previous view, remarking that:

... the evidence suggests that current transmission planning and investment arrangements are delivering efficient outcomes. Put simply, where interconnection development is economically efficient it has, and is, occurring in a timely manner. (sub. 22, p. 1)

It went on to note that a lack of major new interconnector projects is not necessarily inefficient and can in fact indicate that the regulatory framework is working as intended, to ensure that only efficient investments are built:

Regular analysis ... has shown that in most cases the benefits of building additional interconnection capacity would not outweigh the costs. Given an environment of concern about rising electricity prices, it is important that the framework ensures that interconnection investment is undertaken only in the circumstance where it provides a net benefit. (sub. 22, p. 2)

Several generators also submitted views regarding the level of interconnection (box 17.1).

Box 17.1 **Generators' views on interconnectors**

Loy Yang Marketing Management Company highlighted the 'uncertainty that currently exists with regard to future interconnector carrying capacity for market participants'. It argued that this warrants the adoption of interconnector reliability standards to ensure that interconnector capacity is not eroded over time by, for example, new generation investments (sub. 25, p. 2).

International Power-GDF Suez Australia stated that it only supported 'rational interconnector investment that is underpinned by sound economic cost-benefit analyses' (sub. 36, p. 9), but also noted that developments in the market might heighten the impact of congestion and increase the future importance of interconnection:

The NEM and the external environment have evolved to the point where we now see the progressively increasing impact of transmission issues on generator connection, network access, congestion and inter-regional trading. These issues have become even more critical as the market attempts to respond to the transformational challenges arising from the shift to clean energy. (sub. 36, pp. 8–9)

The company also referred to the link between congestion and price volatility, and hence on the risks of trading between regions in the NEM:

The ability to trade power contracts between regions with confidence is a highly desirable outcome for the NEM. To do so currently requires a market participant to bear significant inter-regional price risk. ...

Price differences themselves are not a problem, but rather their highly volatile nature. A major component of this volatility is introduced by transmission congestion – both within regions and between regions.

This overall price difference volatility is a deterrent to inter-regional trading. A generator or retailer that seeks to contract in a region outside its own faces significant risks if it is left unable to defend these contracts in the event of transmission congestion or inter-regional separation. (sub. 36, p. 9)

The National Generators Form cautioned against the introduction of any requirements for transmission network service providers to undertake particular (interconnector) investment. The forum also considered that recent changes to the regulatory framework, particularly through the (new) Regulatory Investment Test for Transmission (RIT-T) mean that there is now:

... a robust and thorough assessment process to consider and measure the net efficiency gains from any interconnector project.

... the RIT-T, in combination with the incentives provided by the transmission building block regulatory regime, is capable of promoting timely and net beneficial transmission investment. (sub. 33, pp. 3, 5)

A divergence of views was similarly evident amongst energy user groups. The Major Energy Users highlighted the low level of recent investment in interconnectors, noting that, with the exception of Basslink:

Since the beginning of the NEM, there has been no significant investment in interconnection yet there has been massive investment (measured in \$billions) in transmission networks as a whole. (sub. 11, p. 19)

However the Energy Users Association of Australia submitted that there is ‘little evidence’ to suggest a need for greater interconnection (capacity) — though it stressed that this did not obviate the need to look more generally at the reasons for significant differences in regional electricity prices:

Significant and sustained price differences between NEM regions are not, in our view, necessarily indicative of insufficient interconnection. There might be many reasons for high prices in individual NEM regions, such as the exercise of market power, market design features, inadequate demand-side participation, poor price signalling to consumers, amongst other factors. Significant price differentials between NEM regions might be more efficiently dealt with through changes in these areas, [rather] than through greater interconnection. (sub. 24, p. 13)

Finally, and in line with Garnaut’s comments, some participants (such as the Clean Energy Council, sub. 31), focussed on the particular role of interconnectors in transporting low-emissions energy between jurisdictions, and the need for greater coordination in investment planning to facilitate this.

As the subsequent sections make clear, assessing the validity of these claims is not straightforward. Thus before reviewing the evidence regarding the adequacy of current interconnection, the Commission has sought to outline some important conceptual considerations that bear upon such an assessment.

17.2 Some conceptual considerations

The benefits of interconnectors must of course be weighed against their costs. But while it is easy to understand the costs of an interconnector in engineering and financial terms, the benefits from greater interconnection are less tangible, and more varied. The RIT-T (discussed in more detail in chapter 19) contemplates a range of benefits that might arise from a new transmission investment (including interconnectors). These include lower fuel costs, reductions in unserved demand, delayed or avoided investment in intra-regional transmission or generation assets and the benefits from increased competition. Also important is the role of interconnection in facilitating an efficient level of congestion across the network.

Welfare effects from greater interconnection

By allowing interconnection between regions, an interconnector project can defer other transmission or generation investment. It can also improve productive and allocative efficiency in the interconnected market, by introducing further competition for generators, and enabling consumers to access more (and potentially cheaper) sources of energy.⁶

While many of the effects would be transfers (for example, consumers in an exporting jurisdiction would likely face higher prices, while those in the importing jurisdiction would see price falls), with sufficient interconnection, there is likely to be a net welfare gain across the jurisdictions. This is best illustrated by a simplified example where a connection is introduced between previously unconnected low cost (exporting) and high cost (importing) regions (box 17.2).

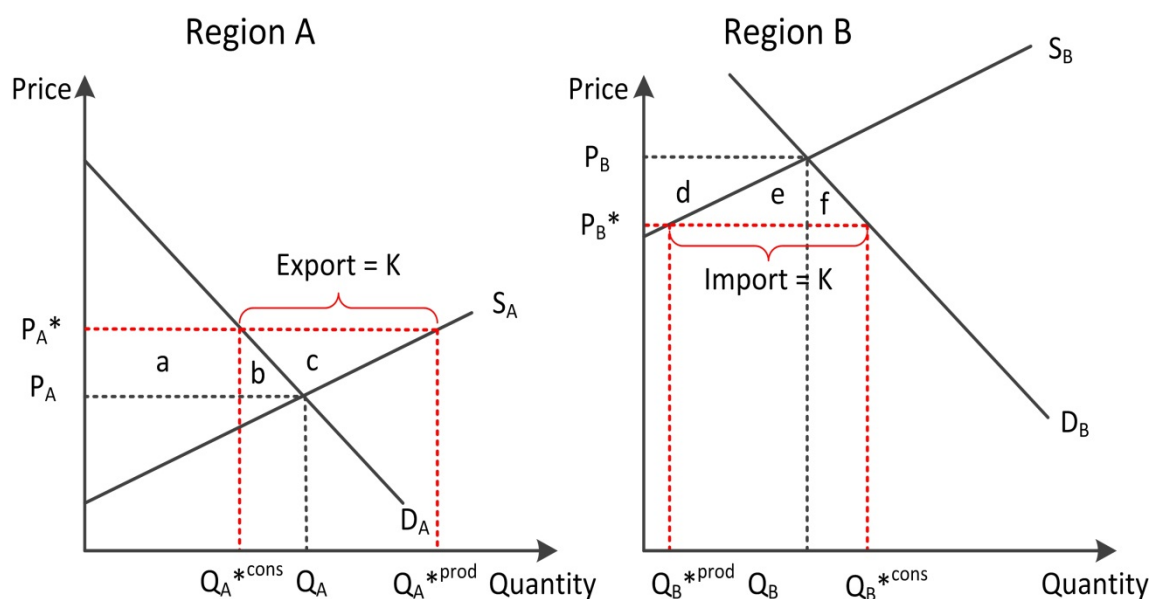
At the same time, a welfare enhancing interconnection can create ‘winners and losers’ through its redistributive effects. Although these winners and losers ‘wash out’ in the assessment of a net benefit, their identification during the assessment process can be important. For example, the process of identifying beneficiaries is central to ‘beneficiary pays’ models of transmission expansion (see, for example, Hogan 2012a).

Net welfare effects (the change in consumer and producer surplus) are typically a reflection of movements in prices. In reality, such movements can occur for a variety of reasons. For example, if generation in neighbouring jurisdictions relies on fuel sources with different characteristics, price movements in those fuel sources can move in unrelated ways at different times. Connecting the regions can allow consumers to ‘smooth’ the costs, a point Turvey (2006) noted in commenting on a proposed interconnector between the largely hydro system of Norway and the largely thermal system of Britain:

In wet years such an interconnector would have added to total Norwegian export possibilities, so raising prices, while in dry years it would have extended the import possibilities, so reducing import costs; in other words there would have been a favourable terms of trade effect in some years. As regards daily variations on the other hand, the interconnector would have added to Norway’s capability for export using its hydro capacity, allowing it to earn more on peak power exports. (p. 1459)

⁶ ‘Cheaper’ in this instance refers to savings in fuel and other variable operating costs. Greater interconnection can also allow for more flexibility of choice in regard to generators, potentially avoiding or reducing ‘start up’ costs incurred from bringing additional peak generators online.

Box 17.2 Illustrative welfare effects from interconnection



As the figure above illustrates, the introduction of an interconnector with a capacity of 'K' leads to some degree of price convergence, as the price rises to P_A^* in the exporting region (region A) and falls to P_B^* in the importing region (region B).

In terms of welfare effects, in the exporting region the higher price results in a loss to consumers (of surplus represented by the area 'a+b') but a gain to producers ('a+b+c'), and a net welfare gain for the region ('c').

For the importing region, consumers gain from lower prices and associated greater consumption ('d+e+f'), but the producers now receive a lower revenue through reductions in both quantity and 'domestic production (the area 'd')'. Again, there is a net welfare gain to the importing region ('e+f'), and an overall gain to both regions ('c+e+f').

There might also be dynamic efficiency gains if generators in one location are less costly (at least at some times) than generators in other locations. Those cost efficiencies might see the migration of investment to lower-cost generators, especially where the decisive factor is cheap fuel source availability. The point here is that 'transfers' can create rents (or losses) for generators that create incentives (or disincentives) for long-run investment and attempts to encourage cost minimisation. Much the same imperative underpins incentive regulations for electricity networks.

Source: adapted from Kapff and Pelkmans (2010).

While many of these effects will be reflected in movements in electricity prices, there will be exceptions. For instance, an interconnector might provide other benefits, such as avoiding generation investment required for security of supply (discussed below).

An efficient level of congestion

Congestion in a transmission system can lead to higher electricity prices as potentially cheaper sources of generation are effectively disconnected from the market and progressively more expensive sources must be relied on to meet demand. This can also result in transient (or ‘time-limited’) market power for some generators. Should the generators respond to market incentives and decide to wield their market power, it could lead to further price spikes. Congestion can also affect reliability and result in load shedding if sufficient generation is not accessible in time to meet demand requirements. As such, reductions in congestion — through intra- or inter-regional transmission investment — can be beneficial.

However, the efficient level of congestion is not zero. The benefits of reducing congestion must be set against the investment and other costs of doing so. As the AEMC stressed in its Congestion Management review of 2008:

To eliminate *all* transmission congestion would be neither cost-effective nor efficient. It would lead to over-investment in transmission capacity. In the NEM’s radial network with dispersed sources of generation and centres of demand, the costs of building out all transmission congestion would be prohibitively high. There is, therefore, an *efficient level* of congestion ... (2008b, p. 10)

The implication is that a lack of new investment in interconnectors does not automatically mean that the regulatory framework has ‘failed’ — it might simply be that the costs of alleviating identified congestion would outweigh the benefits. This in turn means that the regulatory framework should not be judged on the quantum of investment that does (or does not) go ahead. Rather, the pertinent questions are:

- Were efficient investments correctly identified and evaluated?
- Did only those investments that were judged as efficient go ahead?
- Did any investments that were judged as efficient *not* go ahead?

(Related issues are the categories of benefit that should be included, and the method of reaching judgements about the level of efficiency of any given investment. These questions are considered further in chapter 19.)

Other potential benefits from interconnection

Encouraging financial trade in the energy market

Wholesale electricity spot prices are volatile, exposing generators and retailers to risk. As Parer (2002, pp. 129–30) observed:

Irrespective of the level of interconnection, physical constraints between regions are of critical concern where they undermine the development of efficient levels of contracted interstate trade towards a truly national and efficient energy market and efficient integration of the NEM at a wholesale and retail level. The key issue is the ability of market participants to manage the financial risks that result from the potential for interconnectors to physically constrain or fail.

The Commission concurs that there could be benefits of this nature from greater interconnector capacity — though such capacity is only one factor affecting inter-regional financial trading. Indeed, some other factors (such as market rules and participant behaviour) seemingly have more frequent and adverse effects on trading risk than the current capacity of interconnectors. These issues are further explored in chapter 18.

Accessing alternative fuel sources

Garnaut and others suggest that greater investment in renewable generation will increase the importance of interconnectors. For example, the Clean Energy Council submitted that:

High penetrations of renewable generation imply technology and geographic diversity. Under this condition cases are envisaged to arise where load and generation capacity will not always align within a region. In other words one region may have significant generation potential at a time when demand within that region is low and is exceeded by the generation capacity. To illustrate, if wind generation in South Australia exceeds overnight demand, the excess generation could be used in Victoria via interconnectors. (sub. 31, p. 5)

AEMO also pointed to the challenges that integrating renewable technologies, particularly wind energy can cause, and suggested that a national planner (who is capable of planning and directing both intra- and inter-regional transmission investment) was best suited to integrate government energy policies with the existing NEM in an efficient manner (sub. 32, p. 33).

Absent policies mandating a certain level of renewable energy use, the benefits of facilitating inter-regional flows of renewable energy would simply be one component of the overall benefits of trade in electricity across the NEM.

However, access to renewable energy sources that are intrinsically efficient (that is, which do not require subsidies) are likely to increase the scope for welfare enhancing trade of this nature as noted above, the benefits of interconnection are likely to be greater when neighbouring jurisdictions rely on different fuel sources. If fuel sources (and their associated costs) are largely the same, cost savings from greater interconnection might be smaller (but other impacts, such as mitigating any

generator market power, benefits of scale of particular generators or reducing costs of meeting reliability requirements would still be present).

Moreover, in the presence of current policies mandating a certain level of renewable energy, greater interconnection could have a more specific benefit through reducing the cost of meeting those requirements. In effect, interconnection will facilitate the use of the most cost-effective renewable resources across the NEM, rather than within each jurisdiction.

But this would be very much a second best benefit. To the extent that mandatory renewable energy targets impose net costs, the best policy is to remove them, not seek to alleviate that cost through further investment in interconnectors.

17.3 Evidence of the efficiency of interconnection

There is no single, conclusive measure to determine if interconnection in the NEM has reached (or is likely to remain at) an efficient level. Nevertheless, some indicators, in tandem, provide evidence on efficiency:

- cost–benefit analyses undertaken for potential interconnectors as part of RIT-T processes and in the National Transmission Network Development Plan (NTNDP)
- measures of the cost of congestion
- the level of price separations between regions in the NEM
- the extent of the utilisation of interconnector capacity.

Cost–benefit analyses of potential interconnectors

Three interconnectors in the NEM (Heywood, QNI and Vic-NSW) are undergoing some evaluation by the relevant TNSPs (and AEMO in the case of Heywood) to determine what, if any, upgrades would be efficient. While these analyses have not been finalised, the information that is available provides insights on both the adequacy of current interconnection capacity, the relative merits of different forms of upgrades (as well as on how the decision making process proceeds).⁷

⁷ Electranet and AEMO published a Project Specification Consultation Report (PSCR) examining potential upgrades to the Heywood interconnector in October 2011, and a Project Assessment Draft Report in September 2012. Powerlink and Transgrid published a PSCR examining QNI (the Queensland –New South Wales Interconnector) in June 2012, and the AER (sub. 13, p. 25) advised that AEMO and Transgrid have ‘indicated they intend to investigate the benefits of

The RIT-T process for the Heywood interconnector

As the transmission planners for Victoria and South Australia respectively, AEMO and ElectraNet initiated a RIT-T for the Heywood interconnector following the identification of market benefits from such an expansion in the 2010 NTNDP. The first stage of the RIT-T process is a Project Specification Consultation Report (PSCR). This report is designed primarily to facilitate consultation from interested parties by describing the ‘identified need’ (reason for new investment), ‘credible options’, and technical requirements for non-network solutions. Accordingly, the PSCR for the Heywood interconnector (AEMO and ElectraNet 2011a) does not provide detailed cost–benefit analysis of any of the two network or two non-network solutions it describes.

An earlier feasibility study undertaken by AEMO and ElectraNet (2011b) did consider the net benefits of some upgrade options, and indicated that an incremental option (the addition of a third transformer at the Heywood terminal station, which would increase the interconnector’s capacity from 460 to 650 MW) would be most likely to provide economic benefits in the medium term. While the feasibility study represents ‘early estimates’ of both the costs and benefits, and has not been subject to stakeholder analysis, it illustrates the potential net benefits from interconnector augmentation. The study concluded that the incremental option:

... was shown to be economically feasible as early as 2017-18 under high growth and [then] carbon price conditions and with significant wind investment in South Australia. The optimal timing of the incremental option was delayed under less favourable conditions. ... if other market benefits are taken into account (e.g. competition benefits) the timing could be advanced. (AEMO and ElectraNet 2011b, p. 11)

In relation to other, high capacity (2000 MW) augmentations, the study concluded⁸ that such an option:

... could be justified under high growth and carbon price conditions and with significant committed wind investment in South Australia ... as early as 2020 to 2025. (AEMO and ElectraNet 2011b, p.11)

In September 2012, AEMO and ElectraNet (2012) released the Project Assessment Draft Report (PADR) for the Heywood RIT-T. The PADR reported on cost-benefit analyses of six main options (and two minor variants to those options). Broadly, the PADR confirmed the outcome of the earlier feasibility study and favoured the addition of third transformer at the Heywood terminal station. This option (‘1b’)

upgrading the Victoria to New South Wales interconnector. The analysis for this investigation is not yet public’.

⁸ The study also noted that the timing for the high capacity option could be brought forward in the presence of additional incentives for renewable power (AEMO and ElectraNet 2011b, p. 11).

was assessed as providing a net market benefit of \$190 million (AEMO and ElectraNet 2012, p. ix).

However, another option (option 6b — involving similar additional work to option 1b, but with control schemes used instead of adding a third transformer) was found to have net benefits of \$189 million (AEMO and ElectraNet 2012, p. ix). Although this option showed smaller benefits (\$253 million as against \$270 million), it also involved smaller costs (\$64 million as against \$80 million).

Although these options are estimated to have nearly identical net benefits, AEMO and ElectraNet noted that the control schemes involve additional risks (relating to technical feasibility and commercial issues such as the assignment of liabilities, among other things). In addition, the third transformer also provides benefits through limiting the reduction in the interconnector in the unlikely event of a failure of the existing transformers. Based on these additional considerations, AEMO and ElectraNet have identified the addition of a third transformer (option 1b) as the preferred option for increasing the capacity of the Heywood interconnector.

Importantly, the RIT-T assessment found that a larger increase in the capacity of interconnection between Victoria and South Australia (a new Krongart-Heywood interconnector which would increase overall capacity by 1940 MW) would be both costly (\$212 million), and would not have substantially greater benefits (\$303 million) than the preferred option. Accordingly, while still having a projected net benefit, the size of that benefit was less than half the preferred option (AEMO and ElectraNet 2012, pp. vii-ix).

By indicating that a relatively incremental solution is likely to be the best option, both the feasibility study and the PADR serve to illustrate that ‘bigger is not always better’, and provide a reminder that the costs of augmentation play a significant role in determining the net benefits that arise.

The RIT-T process for QNI

As with the Heywood RIT-T process, Powerlink and Transgrid recently published the PSCR for a potential upgrade to the QNI interconnector. The PSCR describes the identified credible options, and provides preliminary cost estimates and indicative figures for the increase in capacity associated with each option. They have not yet published cost–benefit analyses of the options.

However, this current process is not the first consideration of an expansion to the capacity of QNI. To date, the most significant increase in capacity on this interconnector has come about not from additional built network infrastructure, but

rather from testing and refining control systems to use the existing infrastructure more efficiently (Powerlink and Transgrid 2012, p. 8). A previous application of the (then) Regulatory Test in 2008 concluded that the optimal timing of upgrades to QNI was (then) well into the future (Powerlink and Transgrid 2008, p. 3). In the PSCR itself, Powerlink and Transgrid note that various factors, including generation and load developments (as well as the RIT-T itself) have changed since the 2008 assessment, prompting a re-evaluation of potential upgrades (Powerlink and Transgrid 2012, p. 8).

This example highlights the ongoing nature of transmission planning, as well as the necessity to re-examine past forecasts in the face of changing conditions.

Cost–benefit analysis of ‘NEMLink’ in the National Transmission Network Development Plan

In addition to analyses carried out by transmission businesses in relation to their planned upgrades, AEMO — in its role as National Transmission Planner — separately publishes the NTNDP on an annual basis. The NTNDP involves consideration of increasing interconnection in the NEM through a conceptual project called NEMLink, which focusses on a high-capacity transmission ‘backbone’ through the NEM.

AEMO’s analysis suggests that building NEMLink would not be economically viable at this time. Indeed, the most economic option for NEMLink — which defers the costly Victoria–Tasmania component of the link — is still judged to have a negative net present value (in 2010-11 dollars) of -\$400 million (AEMO 2011d, p. 6-8).

AEMO went on to note that with increasing demand, NEMLink might become viable sooner under high demand and high carbon price conditions. However, a more likely scenario is that NEMLink would only be viable in 15 to 20 years from now (AEMO 2011d, p. 6-1). Indeed, AEMO was sceptical that the NEMLink could be realised at all in the current environment of jurisdiction-based planning, even if it had a positive net present value:

The NEM framework is incapable of delivering projects like NEMlink.

It would require significant coordination and cooperation of five transmission planners, alignment between the allowances in the revenue resets of each of the regulated businesses. The history of Inter-Regional Planning Committee (IRPC) suggests that such cooperation and coordination would not work in practice. (sub. 32, p. 32)

Nonetheless, the analysis seems reasonably clear that, at this time, investment in this expensive project would not be economically efficient. More generally, it

illustrates that the regulatory framework is continuing to evaluate the need for further interconnection, and only responding with investment when it is efficient to do so.

The cost of congestion

While it is difficult to identify any single, efficient level of congestion, examining measures of congestion, and particularly their movement over time, can provide an indication of how well the regulatory and investment framework is working.

The ‘total cost of constraints’

The ‘total cost of constraints’ (TCC) measures the impact of congestion in the NEM-wide transmission network as the total increase in the cost of producing electricity due to transmission congestion (which includes outages and network design limits) (AER 2009a, p. 142).⁹ The AER has also produced other estimates that focus only on congestion caused by network outages (the ‘outage cost of constraint’) and the marginal cost of constraint (that is, the saving in production costs if congestion on a transmission line is alleviated by one marginal MW of capacity).

The AER’s analysis suggested that the annual cost of congestion rose from \$36 million in 2003-04 to \$189 million in 2007-08, but fell to \$83 million in 2008-09. However, congestion was not uniform throughout any given year. Around two thirds of the total cost for 2007-08 was accounted for by just 26 days, with nearly 60 per cent of the costs attributable to network outages. In 2008-09 around two thirds of the total cost accrued on 13 days, with just over 40 per cent of the costs attributable to network outages (AER 2009a, p. 143). While it is difficult to isolate a sole cause for the substantial drop in the impact of congestion in 2008-09, the AER considered that recent regulatory changes had encouraged additional investment (AER 2009a, p. 143).

The AEMC also found little evidence of costly congestion, with costs representing less than 0.5 per cent of the NEM’s total production costs in 2007-08 (box 17.3 and AEMC 2008b, p. 15).

⁹ The AER published four annual reports on congestion from 2003-04 to 2006-07. The reports were an input into the development of a new parameter in the service target performance incentive scheme for transmission companies. The parameter was first applied in 2009 (AER 2009, p. 143).

Box 17.3 Evidence in the AEMC's 2008 Congestion Management Review

As part of its Congestion Management Review, the AEMC considered evidence from several sources on the pattern of 'mis-pricing', including the National Electricity Market Management Company Limited's (NEMMCO) Statement of Opportunities – Annual National Transmission Statements, work conducted by Dr Darryl Biggar (an economic consultant to the Australian Competition and Consumer Commission and adviser to the AEMC for the review) and NEMMCO. Some key findings were:

- Biggar concluded that the NEM-wide incidence of mis-pricing has increased since 2003-04. He found that mis-pricing was a frequent and enduring issue at a relatively large number of connection points, stating that some 95 connection points were mis-priced for an average of more than 100 hours per annum over the three years of his study (2003-04 to 2005-06).¹⁰
- NEMMCO's preliminary study confirmed Biggar's finding that there had been an increasing trend in mis-pricing from 2003-04 onwards. However, it also showed that over the study period (2001-02 to 2005-06) the number of connection points being mis-priced was fairly steady. NEMMCO noted that the reasons for these trends were specific to the region and the situation at the time.
- Generators were significantly more likely to be positively mis-priced (constrained-off) than negatively mis-priced (constrained-on). In 2005-06, the ratio between the two forms of mis-pricing was three to one.
- The average mis-priced amount per mis-priced dispatch interval was very high, ranging from around \$500 to \$1000 per MWh for generators that were positively mis-priced and from around -\$300 to -\$6000 per MWh for generators that were negatively mis-priced. These results suggest there is a high probability that disorderly bidding occurred when a constraint bound.
- Biggar found that only a small number of connection points were mis-priced by more than \$5/MWh for all three years of his study. These connection points all related to small gas or hydro plants in Queensland.
- Biggar also found that average hours of mis-pricing due to system normal events were fairly constant over the three years, at around 50 hours per year. However, there was an increasing trend in the duration of mis-pricing due to transmission outages, from 20 hours in 2003-04 to over 120 hours in 2005-06. This was mainly due to the increased incidence of outage-caused congestion in both the Snowy and Queensland regions. The Queensland increase was due to lightning events affecting flows between Central and South Queensland and an outage at the Gladstone transformer.

Source: AEMC (2008b).

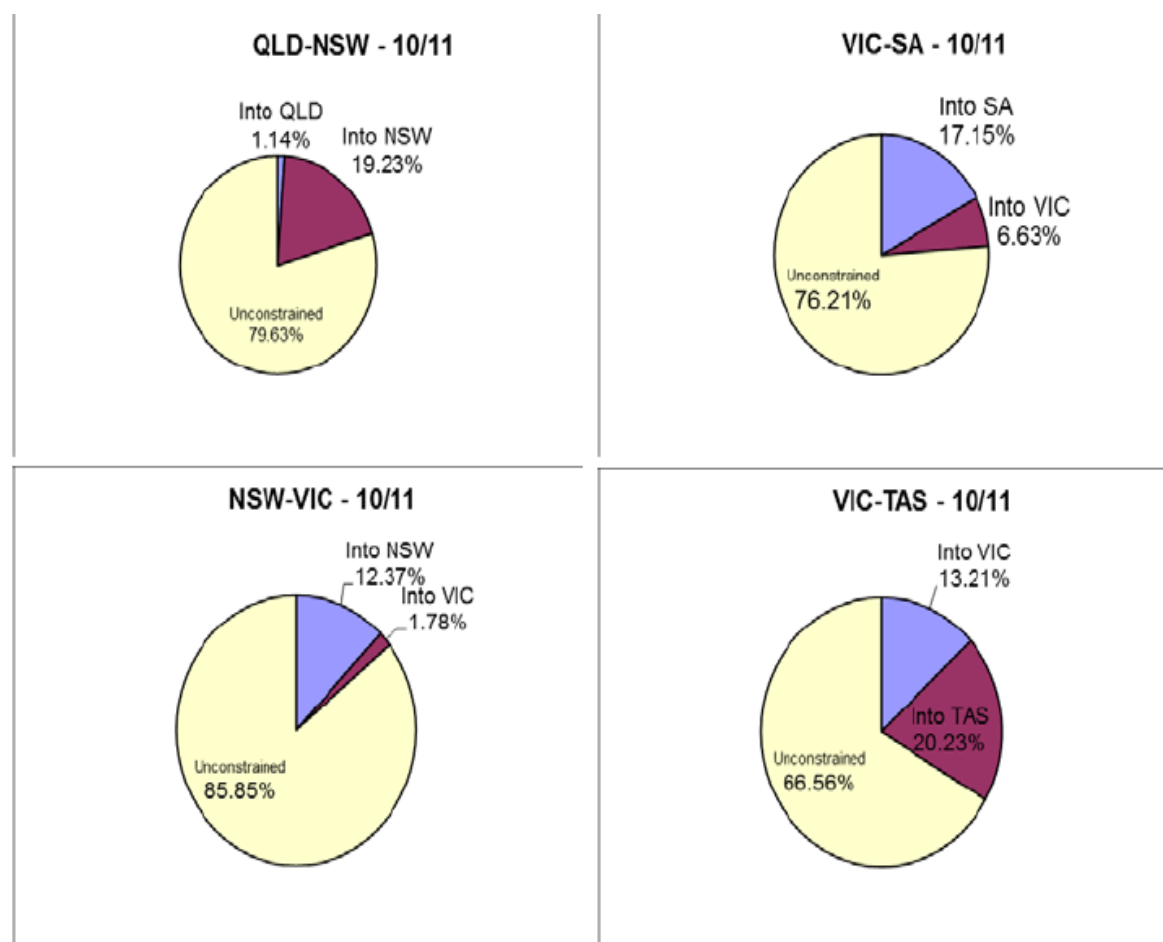
¹⁰ The AEMC note that, in the presence of congestion, the (implied) local price of a generator and the regional price can diverge. They term this phenomenon 'mis-pricing', which creates dispatch risk and leads to disorderly bidding (AEMC 2008b, p. 8).

Price separations in the National Electricity Market

In theory, complete integration of the regions in the NEM would result in equal prices across the NEM (allowing for differences in transmission losses). However, because some congestion is optimal, sporadic interregional price differences (or ‘price separations’) are not necessarily inefficient.

Indeed, evidence provided by the National Generators Forum (NGF, sub. 33) suggests that in the relatively infrequent number of cases where interconnector congestion is encountered (figure 17.4), the resulting price differences are typically small. Specifically, in more than 90 per cent of such congestion events in 2010-11, the price difference was less than \$50 per MWh (table 17.2).

Figure 17.4 Percentage of interconnector time constrained, 2010-11
Per cent of half hour periods



Data source: NGF (sub. 33, p. 6).

Table 17.2 Price separations by interconnector, 2010-11

Share of separations (%)^a, by price category

<i>Line/direction</i>	<i><\$0</i>	<i>\$0<\$50</i>	<i>\$50<\$100</i>	<i>\$100<\$200</i>	<i>\$200<\$500</i>	<i>\$500<\$1000</i>	<i>\$1000<\$12,500</i>
QNI - to Qld	0.8	95.8	1.3	0.3	0.3	1.3	0.3
- to NSW	0.8	97.9	0.5	0.2	0.1	0.1	0.4
Vic-SA - to SA	70.7	27.9	0.3	0.2	0.5	0.1	0.3
- to Vic	1.9	93.0	3.0	0.5	0.4	0.3	1.0
Vic-NSW - to NSW	0.9	94.1	1.8	0.9	1.5	0.1	0.6
- to Vic	0.0	99.5	0.4	0.0	0.1	0.0	0.1
Basslink - to Vic	2.9	94.9	0.9	0.4	0.7	0.1	0.2
- to Tas	2.5	94.9	2.1	0.1	0.3	0.0	0.2

^a Shares have been rounded to one decimal place.

Source: adapted from NGF (sub. 33, pp. 9-10).

The NGF also reported that the percentage of half hours when price separation was less than \$10 ranged from 95 per cent on Basslink, to 62 per cent from New South Wales to Victoria (sub. 33, p. 7).

The Commission notes that while the figures submitted by the NGF report a low *frequency* of price separations, and particularly of incidents of greater separation, the information submitted does not (nor does it attempt to) reflect the *effect* of those separations.¹¹ Further, these data represent a ‘snapshot’ of separations. Price separations are becoming more frequent, occurring 20 per cent of the time in 2001-02, 33 per cent in 2009-10 and 39 per cent in 2010-11 (AER 2011b, p. 34). Hence, caution is required in drawing overly strong conclusions from the sort of data submitted by the NGF.

The Commission seeks further evidence, and participants’ views, on the impact of price separations between regions in the National Electricity Market.

There are unusual patterns in the utilisation of interconnectors

The economic effects (including price impacts) of interconnectors are determined by the amount of power transported across regions (utilisation), not the built capacity of interconnector. Utilisation often appears to be relatively low.

¹¹ For example, while a separation of up to \$12 500 for flows into New South Wales on the Victoria–New South Wales interconnector appears to be roughly 150 times less frequent than those under \$50, if the difference in price on those occasions is, say \$12 450 as against \$49 (250 times larger), then the economic impact would be considerably higher. It may also be the case that larger price differences tend to occur more often at peak times, increasing the quantity of power involved and thus exacerbating the impact of a given price difference.

One example of this was highlighted by the Energy Users Association of Australia (sub. 24). Up to 2006, the Heywood and Murraylink interconnectors supplied around a 20 per cent (aggregate annual) share of South Australia's electricity, 'but since then it has ranged between almost no share and a 5 per cent share, although gradually increasing since 2007' (EUAA, sub. 24, p. 15). Paradoxically, the share of power supplied appeared to drop at the times when the interconnectors would be expected to be flowing at capacity. The average share of the electricity supplied through the interconnectors, during the 72 highest price half-hourly settlement periods (that is, peak times) from 2008 to 2010, was around 10 per cent (EUAA, sub. 24, p. 14).

The EUAA further examined the interconnector capacity in both peak and average annual terms (table 17.3). It found that even during the hot years of 2008 and 2009 the interconnectors' utilisation was only 'a little over half' of their capacity (sub. 24, p. 16). Yet, during these years, the highest 72 half-hourly settlement prices in South Australia were never less than \$376 per MWh, and averaged \$7180 per MWh.

Table 17.3 South Australian interconnector capacity factors

Heywood and Murraylink, shares of peak annual transfer capacity, per cent.

<i>Year</i>	<i>Capacity factor^a in highest 72 settlement periods</i>		<i>Average annual capacity factor</i>	
	<i>Vic to SA</i>	<i>SA to Vic</i>	<i>Vic to SA</i>	<i>SA to Vic</i>
2005	39	33	41	2
2006	46	2	40	3
2007	8	33	13	19
2008	54	4	14	18
2009	52	6	20	16
2010	41	8	23	14
2011	55	4	27	11
Average	42	13	25	12

^a 'Capacity factor' refers to the utilisation of the interconnectors as a percentage share of their listed capacity.

Source: EUAA (sub. 24, p. 16).

Several factors might explain these seemingly odd outcomes:

- high prices in South Australia might have coincided with high prices in Victoria, in which case below-capacity flow on the interconnector would be efficient
- a physical constraint on the interconnectors themselves, or elsewhere in the transmission network, might have constrained the interconnector flow to below the listed capacity

-
- generating capacity might have been withheld (the view of the EUAA (sub. 24, p. 17) which found that surplus generation capacity was available at times of very high prices).

The potential withholding of capacity was one of the issues examined by the AEMC in its rule change regarding potential generator market power in the NEM (AEMC 2012m). In its draft rule determination, the AEMC found that:

... there is a noticeable reduction in capacity utilisation in South Australia at prices above \$250/MWh. This reduction contrasts with much smaller reductions or even increases in the other NEM regions. While there are myriad reasons as to why levels of capacity utilisation at high prices are lower in South Australia, including more frequent outages or the responsiveness of generation plant, it is of note that the primary driver of the fall in South Australian capacity utilisation when prices are above \$250/MWh is AGL's operation of the Torrens Island power station. (AEMC 2012m, pp. 41-2)

The AER likewise drew attention to the behaviour of the Torrens Island Power Station:

In only two of the 26 half hour periods where price exceeded \$5,000/MWh was more than 700MW of the Torrens Island's capacity dispatched (Torrens Island Power Station's total capacity is 1 280MW). In over a third of these half hourly periods, *under 300MW* of the total capacity of Torrens Island was dispatched. (AER 2012i, p. 10)

In his examination of the exercise of market power in the NEM, Biggar also concluded that 'out of 57 high-demand days, on 30 occasions [Torrens Island Power Station] appears to have been directly exercising market power with withholding capacity' (Biggar 2011c, p. 49).

More generally, the issue of generator market power in South Australia has been the subject of substantial commentary, including as part of the AEMC's rule change process (box 17.4). While the AEMC acknowledged factors that led to positions of market power, they concluded that any exercise of market power was likely to be *transient* (that is, took advantage of temporary conditions), and not substantial.¹² However, some others were more concerned. For example, as part of the rule change process, the AER submitted that 'it appears that there has been the exercise of substantial market power, particularly in South Australia' (AER 2012i, p. 1). And, in Biggar's view, there had been a 'significant' exercise of market power that 'persisted for three consecutive summers' (Biggar 2011c, p. 61).

¹² Importantly, this discussion considers only the *exercise* of market power, not its *misuse*. As such, the discussion here (and in the sources referred to) is not concerned with proving an offence under the *Competition and Consumer Act 2010*.

Box 17.4 Generator market power in South Australia – the AEMC’s view

In examining the issue of generator market power in the NEM, the AEMC (2012b) found that in South Australia there was:

- some evidence of barriers to entry — one pre-condition for firms to *possess* market power, itself a pre-condition to *using* that market power (p. 42)
- some concern regarding the level of market concentration (p. 41)
- a lower level of contract (or hedge) market liquidity than in other NEM regions (p. 43), and limited transparency with regard to prices and volumes of trade in the contract market due to vertical integration (p. 21)
- wholesale annual average spot prices above a range of long run marginal costs estimates in 2007-08, attributed to restricted interconnector flow. Prices fell just below the ‘high’ end of long run marginal cost estimates, before falling below the range in 2010-11 (p. 28).

Overall, the AEMC concluded that there was insufficient evidence of *substantial* (as distinct from ‘transient’) market power in the NEM, and (at the draft stage) did not agree with the proposed rule. They did note, however, that work undertaken on their behalf by the Competition Economists Group suggested that in South Australia ‘there was evidence that meant that ongoing monitoring prices against the long run efficient level may be warranted’ (AEMC 2012m, pp. ii-iii).

Source: AEMC (2012m).

In its submission to this inquiry the EUAA (sub. 24) argued that a benefit of expanding interconnector capacity would be to promote competition between generators, eroding potential positions of market power. Clearly, a base level of interconnector capacity is necessary to facilitate inter-regional competition. However, given that in the particular circumstances of concern to the EUAA and others there is currently spare interconnector capacity, it seems unlikely that upgrading those interconnectors would be the sole solution (that is not to say that upgrading the interconnectors cannot be beneficial, as identified in the RIT-T analyses discussed above). A potentially more fruitful approach would involve reforms to market design to encourage more efficient bidding behaviour by market participants (chapter 18). This would in turn facilitate more efficient interconnector utilisation, and allow for more accurate decisions about the necessity of any interconnector expansion.

Conclusion

Investment in interconnectors to date appears to have provided a reasonably appropriate level of physical capacity to enable trading in power between regions

(given current network, generation and demand profiles). That conclusion can be reconciled with the existence of congestion at times because — as the cost-benefit analyses that have been done suggest — that in most cases there would be significant net costs from eliminating this congestion. And where net benefits have been identified, such as in an expansion of the Heywood interconnector, the relevant stakeholders are acting to initiate further investment.

DRAFT FINDING 17.1

The available evidence suggests that, given the existing network conditions, the current physical capacity of interconnectors is reasonably appropriate.

However, price separations can pose a problem. Substantial price differences between regions are infrequent, but separations as a whole are increasing over time (and can still have significant adverse effects even if infrequent).

Moreover, the physical capacity of interconnectors is not the sole determinant of the actual flows of power between regions in the NEM. Accordingly, the apparent under-utilisation of some interconnectors is not necessarily an indication of current excess capacity. Market design (including rules governing bidding), and participant behaviour in response to the incentives created by the market rules, can affect the use of interconnectors. Current underutilisation may create a distorted base for future projections of interconnection needs.

Further, an assessment that the current level of interconnection is reasonably satisfactory does not necessarily mean that the existing regulatory framework will continue to deliver efficient interconnection into the future. Making judgements of efficiency based on the application of the RIT-T assumes that the test is an accurate and appropriate basis for making such decisions, an assumption that warrants examination.

Therefore, in order to judge if the regulatory framework will continue to deliver efficient interconnection, the Commission considers that, beyond assessments of physical capacity, it is important to examine:

- if the installed capacity is being used efficiently and if not, what could remedy this? (chapter 17)
- whether the current regulatory settings for the planning and selection of future investment is appropriate? (chapter 18)
- whether, outside of the regulatory regime, there are any barriers that prevent the future provision of privately initiated (or ‘merchant’) interconnection? (chapter 19)

18 Efficient use of interconnectors

Key points

- The spot market in the NEM is an energy only market, in which lower bidding generators are dispatched first. The regional spot price is set by the marginal generator's bid in each region (state) and all dispatched generators are paid at that spot price. In theory, this leads to efficient generation. In practice, this is not always true.
- In the presence of congestion, the spot price tends to be high. Under current regulations, this encourages strategic behaviour by those generators constrained by line capacity.
 - Rather than making bids that reflect their true cost, they bid down to the (negative) market floor price to ensure dispatch, and are paid at the high spot price. Even an inefficient generator may supply power. This is termed 'disorderly bidding'
- Disorderly bidding can result in productive inefficiency as less efficient generators are dispatched to meet demand. It can also 'shut off' interconnectors through distorted price signals.
 - The long-term effects are greater, and include inefficient generator location and investment and interconnector planning.
- Potential ways of addressing disorderly bidding include applying formulae to market bids in the presence of congestion, or other longer-term methods that ensure generators face their true costs.
- Allowing generators to purchase a given amount of guaranteed access to lines from transmission businesses ('optional firm access') would remove disorderly bidding incentives and introduce locational signalling to generators. (While this would introduce market signals, there would still be a need for transmission planning).
- Electricity hedge markets are state-based. The lack of effective inter-regional hedging products has contributed to this. This has implications for:
 - liquidity in the hedge market
 - generators' choice of location for new investment
 - the ability of generators to use any market power.
- Publishing past hedging positions would increase market transparency, and enable more effective regulation of market power issues, but also has some costs.
- Reforms that address disorderly bidding also address the root cause of problems in the hedge market.
 - In particular, optional firm access would allow firm access rights across interconnectors, which could replace existing financial instruments.

Several elements of the regulatory framework — incentive regulation, regulatory tests and planning — determine the *amount* of investment in interconnectors in the National Electricity Market (NEM). However, the *use* of interconnectors depends on the activity of market participants in buying and selling power in the ‘spot’ (or energy) market, and on congestion in intra-regional transmission lines. The way participants manage their risk in the hedge market can also affect actual power flows. If either of the markets operates inefficiently, interconnectors could be underutilised. As such, reforms to the markets (as distinct from specific interconnector regulation) could provide benefits from a greater degree of interconnection.

This chapter examines the operation of, and incentives set by, both the spot and hedge markets in the NEM.

18.1 The spot market

Because electricity cannot readily be stored and it is generally not possible to determine which generator provided power to which customer, the NEM operates as an ‘electricity pool’ that matches supply and demand.

The NEM is an ‘energy-only’ market, and does not include a separate capacity market.¹ Aside from hedge contracts, generators earn their revenue solely from the spot market.

The spot market in the NEM is subject to many detailed rules, some of which are necessitated by the nature of electricity, and some of which are legacies of the development of the NEM.

Operation of the spot market in the NEM

The general operation of the spot market in the NEM is discussed in chapter 2, but several features warrant specific mention in the context of interconnectors. Dispatch in the spot market is determined by generator bids at five minute intervals.² These

¹ Some other markets, such as the Pennsylvania-Jersey-Maryland (‘PJM’) and New York markets in the United States, use separate capacity markets to ensure the long-term adequacy of power supply within their markets (Frontier Economics 2009). Such markets can include not only generation capacity but also demand response and transmission investment.

² Generators submit bids in a ‘schedule’ (supply Y_1 MW at price P_1 , Y_2 at price P_2 and so on) in daily bids, submitted before 12.30 on the day before supply is needed. They may submit re-bids until five minutes before dispatch. Re-bids may change the volume, but not price of electricity

generator bids are dispatched in ‘merit order’, with lowest price bids first, with progressively more expensive generation called upon as demand increases. AEMO matches these bids — subject to a complex series of constraint equations managing congestion and transmission losses — to equate supply and demand in each five minute period.

The market price is therefore equal to the bid of the marginal generator — that is, the last, most expensive, generator required to match supply and demand.³ As such, for all bar the marginal generator in a given region, any generator receives a price for their power that is higher than its bid price. Accordingly, bids determine the quantity of power dispatched from non-marginal generators, but not their revenues.

As the NEM is a ‘zonal’ market, there is a separate price for each of the NEM’s five regions.⁴ All generators and loads within a region are settled at that regional price, calculated at the nominated ‘regional reference node’ (RRN). At times when demand is sufficiently low and transmission lines and interconnectors are not congested, these regional prices should equate (allowing for transmission losses). However, congestion can cause price separation between the regions. As noted in chapter 17, such ‘price separation’ occurs roughly one-third of the time and is increasingly common (although the degree of difference between prices is in most cases small).

A further feature of the NEM is that the energy market is ‘co-optimised’ with the market for ancillary services (services required to ensure the stability of the power system, and facilitate its recovery). This means that the algorithm for calculating market outcomes ensures that energy demand and stability requirements are jointly met at the lowest cost. Although this co-optimisation might be efficient, it can lead to some outcomes that, when viewed from the perspective of the energy market alone, may appear perverse. For example, co-optimisation can sometimes be the reason for ‘counter-flows’ along interconnectors — that is, where power is observed to flow away from a higher-priced region to a lower-priced one.

offered (AEMO 2010f). Nonetheless, with a sufficiently large number of price bands within a schedule (and re-bidding volume in other bands to zero) re-bidding of volumes, in effect, amounts to price changes.

- ³ The spot price used to settle market transactions is calculated for a 30-minute trading interval as the average of the six dispatch prices during the preceding 30 minutes.
- ⁴ There are other forms of market structure. *Nodal* markets involve many ‘nodes’ — the physical location, or grouping of locations — where power is entered or withdrawn from the network. Under nodal pricing, generators (and in some cases, customers) are settled at the price of their local node, and multiple nodal prices apply in a single market. At the other end of the spectrum, a single price could be applied across an entire network.

18.2 Disorderly bidding

Bizarre outcomes can occur in the NEM. While the near-instantaneous matching of supply and demand is an impressive feat of market coordination, it is possible for the market signals to ‘malfunction’. In these cases, higher cost generators can sell power into the spot market, even where alternative lower-cost generators could provide this power — ‘disorderly bidding’.⁵ Although the main source of these peculiar outcomes is congestion on intra-regional lines, it can have significant effects on interconnectors.

When there is no congestion within a region, generators have an incentive to bid close to their true marginal cost. Bidding too low might result in ‘follow-the-leader’ behaviour by other generators competing to be dispatched, resulting in a spot price that might be lower than the generator’s marginal cost. Depending on the amount of power dispatched (and their positions in the hedge market), this could be a ruinous outcome for a generator. Conversely, bidding too high could mean not being dispatched when it would have contributed to profits.

However, congested transmission lines create different incentives. Congestion on a transmission line that links one group of generators to the network means that these generators are unable to dispatch all of their supply. Consequently, generators not affected by the constrained line must supply more power than usual. Given the operation of the ‘merit order’ dispatch, and especially at peak demand times, this will mean that a higher-cost generator will be dispatched for at least some of the power required.

Knowing that their bid will not affect the regional price and faced with limited line capacity, the constrained generators’ objective changes. They now have an incentive to bid as low as possible, in order to maximise their share of dispatch on the congested line and to maximise their returns.

Since generators are able to bid a (negative) price floor, currently -\$1000 per MWh, all constrained generators with a marginal cost below the likely regional spot price will bid at the price floor in an attempt to be dispatched. Under the rules, when there are tied bids, capacity is allocated to all of the constrained generators in proportion to their rated capacity. Therefore, even if one low-cost generator were able to meet the full capacity of the congested line, they would have to share supply with higher-cost generators. This results in a higher overall cost to produce electricity for the region.

⁵ The Commission notes that disorderly bidding is a rational (and legal) response to incentives created through peculiarities of market structure. It uses the term in an analytical, not pejorative, sense.

Box 18.1 describes a simplified example where a line connecting two generators to the RRN is constrained. In addition to a fault or outage on a line, congestion can also arise when a new generator connects to an existing line. Where the new generator's capacity tips the total generation supply above the existing capacity of the transmission line, the net effect is the same — generators competing for limited capacity where their bids will not determine the spot price have an incentive for disorderly bidding (AEMC 2011f, pp. 210–12), which has been observed in bidding patterns by the AER (2010c, p. 3).

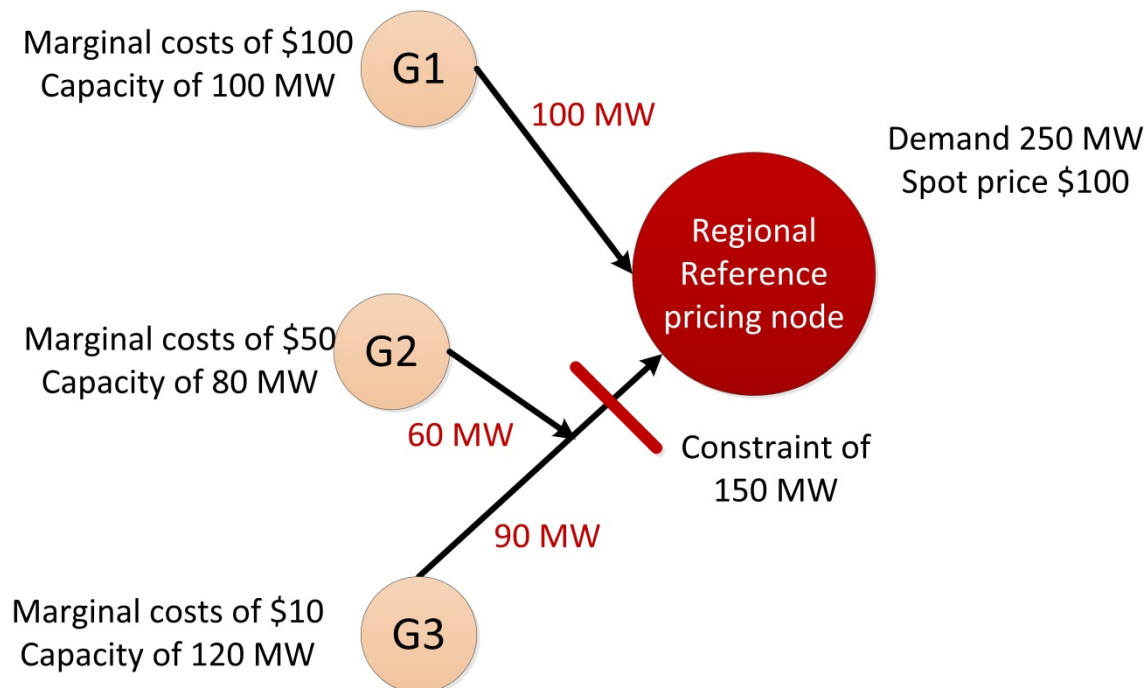
The intrinsic problem is that with transmission constraints, and with the spot price set elsewhere in the region, generators no longer face incentives to bid down to their marginal costs. The duration of constraints can vary — for example, an outage for a few hours, as opposed to the time to construct new transmission to accommodate new generation. Depending on this duration, the demand conditions at the time, and the amount of supply affected, the costs can be large, but transient. While the ACCC has some powers to prevent this, in practice there are significant difficulties in identifying and addressing transient market power, which can manifest as either disorderly bidding, or the more 'traditional' withholding of supply. (Generators have a legal right to change their bids, and there may be many reasons for doing so.)

Though disorderly bidding can cause a range of problems *within* a region, for the purposes of this inquiry, the main problem is the potential impact on the performance of interconnectors (described in a simplified example in box 18.2).

In the spot market, generators in one region receive the *spot* price of that region, even if they 'sell' their power (by contract) to another region across an interconnector (though they may buy hedge products such as 'inter-regional settlement residues', described below, to align their returns with prices in the other region, as discussed below, current methods of hedging are imperfect). Generators in an unconstrained region face the 'normal' incentives to disclose their true marginal cost when bidding, while those in regions with constrained lines have an incentive to enter disorderly bids.

Regulated interconnectors cannot enter retaliatory bids (in the manner that competing generators can), and are instead treated as if they have bid at the RRN in the exporting region. As such, the market would perceive a low cost generator (with say a marginal cost of \$25 per MWh) in the unconstrained region as 'more expensive' than a higher-cost generator in a (constrained) region engaged in disorderly bidding (-\$1000 per MWh) on the other side of an interconnector. In effect, this prevents the supply of lower-cost power across the interconnector into the higher-priced region.

Box 18.1 Disorderly bidding in a single region



In the example above, the transmission line connecting G2 and G3 to the load centre at the RRRN is usually able to carry over 200 MW of power. In this 'unconstrained' case, to meet the region's demand of 250 MW for one hour, the dispatch solution would involve total production costs of \$10 200 and would be divided amongst the generators:

- G3: 120 MW (marginal production cost \$1200)
- G2: 80 MW (marginal production cost \$4000)
- G1: 50 MW (marginal production cost \$5000)

In the presence of a constraint that limits the line to the cheaper generators to 150 MW, G1 must be dispatched for more power (100 MW up from 50 MW). In this situation, G2 and G3 know that their bids will not affect the regional price, so their only incentives will be to maximise their dispatch, not reflect their marginal costs. Both generators will attempt to undercut each other, resulting in bids of -\$1000. G2 and G3 will then be dispatched in proportion to their rated capacity. This changes the dispatch solution:

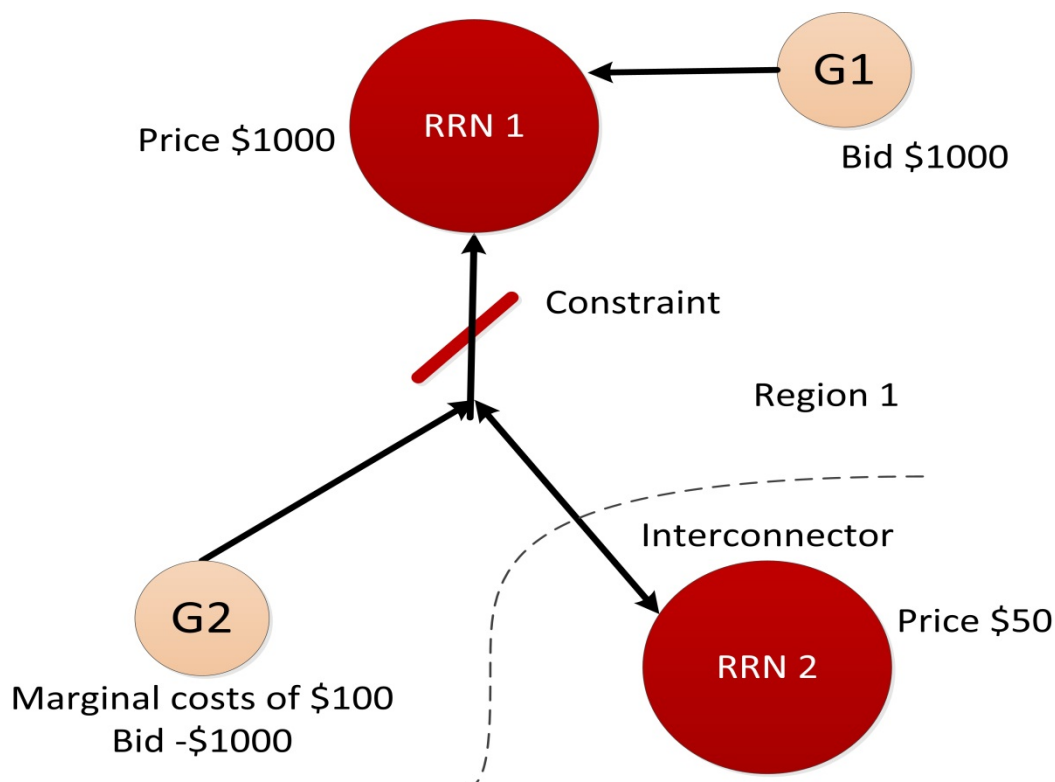
- G3: 90 MW (marginal production costs \$900)
- G2: 60 MW (marginal production costs \$3000)
- G1: 100 MW (marginal production costs \$10 000)

This results in a total production cost for power in the region of \$13 900.

If bids represented 'true' marginal costs, G3 would be dispatched for 120 MW, G2 for 30 MW and G1 would still supply 100 MW. This 'constrained optimisation' solution has a total production cost of \$12 700. As such, in this example, the 'cost' that can be assigned to disorderly bids is \$1200 (with the remaining \$2500 due to the constraint).

Source: adapted from AEMO (sub. 32).

Box 18.2 **Disorderly bidding between regions**



As in box 18.1, when faced with a constrained line, and competition from other generators (whose power must be transferred over an interconnector from region 2), G2 will enter a bid of -\$1000.

In region 2, the marginal bid has set the region's spot price at \$50, and regardless of any power supplied to region 1, a generator in region 2 can only earn \$50 per MWh. As a regulated interconnector cannot 'retaliate' in the market dispatch engine's calculations (by also making a bid of -\$1000), G2's bid of -\$1000 will be treated as a cheaper bid. As such, G2 will run in preference to all generators in region 2, even though there may be many generators with a marginal cost of at least half the fuel cost of G2. This effectively 'cuts off' the interconnector.

In more extreme cases, G2 could export power to region 2, resulting in counter-flows, resulting in AEMO attempting to 'clamp' the flow (see text).

Source: AEMO (sub. 32).

Disorderly bidding is most likely to occur during periods of peak demand — when lines are more likely to be constrained, and when higher cost 'peak' generators are more likely to be called on to meet demand. Ironically, it is precisely at these times when interconnectors should be in most use.

In some circumstances, an even more peculiar outcome arises. A high-cost constrained generator bidding at -\$1000 per MWh is almost certain to have spare capacity (that cannot be dispatched to its regional reference node due to an intervening constraint, but could be dispatched in another direction). Depending on the architecture of the network, its spare capacity could be sent across the interconnector, displacing lower-cost generators in the other region. In these instances of ‘counter-flow’, the availability of the interconnector accentuates the inefficiency of the disorderly bidding.

When counter-flow occurs, negative inter-regional settlement residues (section 18.5) can accrue. To avoid this, AEMO is obliged to ‘clamp’ (artificially reduce) the interconnector flows to zero.⁶ The presence of this obligation is one indicator of the prevalence of disorderly bidding as a problem in the NEM.

Size of the problem?

While disorderly bidding is a well-known phenomenon within the NEM,⁷ some people question whether it matters enough to require a regulatory remedy.

The largest and immediate effect of disorderly bidding are transfers between parties (between generators, and in cases where the region’s spot price increases, between generators and customers). For example, AEMO cited one instance where disorderly bidding lasting just a few hours (from 10.30AM to 5.30PM) had a substantial impact on prices, and on the overall amount paid for power in New South Wales. In this instance, a constraint on the 70/71 transmission lines between the Mt Piper and Wallerawang power stations, combined with generators’ bids, led to spot prices in New South Wales in some instances in excess of \$5000 per MWh, and saw the dispatch engine attempting to reverse interconnector flows away from New South Wales (AEMO 2010g, p. 11). AEMO estimated the revenue impacts of this case of disorderly bidding by comparing the actual outcomes with a ‘re-run’ of the dispatch model using assumed ‘normal’ bidding conditions. AEMO concluded that:

⁶ Such clamping is not always successful, primarily due to generators’ stipulated ‘rates of change’ which affect how quickly a generator’s output can be forced down (or up) and thus allow periods of time where interconnector flows can only be gradually, not instantly, reduced.

⁷ Of course, generators maximising their return in the presence of temporary congestion is not a phenomenon unique to the NEM. In other markets, exercising transient market power can manifest in different ways, for example, there is some evidence of generators withholding supply at times of import congestion in Norway (Mirza and Bergland 2012).

NSW prices between 10:30AM and 3:30PM averaged \$90/MWh in the re-run against the actual average of \$4,917/MWh, which would have reduced pool settlement by about \$300 [million]. (AEMO 2010g, p. 11)

Another example, from 4 February 2010, highlights the interaction between network effects, disorderly bidding and demand response, and the effect this has on price volatility and interconnector flows (box 18.3).

Some have argued that the impact on prices is largely a ‘wealth transfer and not a loss of economic efficiency’ (Frontier Economics 2012, p. 7). However, there are some efficiency effects.

Productive efficiency is lower for the period of disorderly despatch as progressively less efficient generators must be relied upon to meet demand (with the inefficiency mainly being the use of higher cost fuels). As (the bulk of) current generation technologies and fuel sources in the NEM are relatively homogeneous, the differences in short-term marginal production costs are probably not significant.⁸

Moreover, when interconnector flows are reduced (or stopped) by disorderly bidding, it affects the ability of market participants to hedge transactions between regions (section 18.5). This causes greater uncertainty for hedging parties, increasing the cost of hedging and flowing through to higher electricity retail prices.

Further, although they are difficult to enumerate, there are likely to be larger costs in the long term. First, reduced certainty of dispatch due to disorderly bidding can increase the perceived risk of a generation investment, which could discourage (otherwise efficient) investment in new generation (AEMC 2011f, p. 33).

Disorderly bidding widens the margin between the spot price and the usual bidding price of generators (which they typically bid down to their marginal costs). Generators recover their fixed costs from the revenue associated with the spot-bid price margin. Distortions in that margin will affect the future decisions of generators to invest. They could also affect maintenance and asset life decisions if a plant that is able to ‘survive’ on returns from instances of disorderly bidding (rather than by competing on the basis of an efficient marginal cost) is kept online longer than it otherwise would be. Therefore, generators will have a greater incentive to locate new investments in (congested) areas of the transmission network where they can better control dispatch outcomes through disorderly bidding.

⁸ As noted in chapter 17, a Frontier Economics study conducted for the AEMC’s Congestion Management Review (AEMC 2008b) concluded that the (modelled) production costs due to disorderly bidding were only \$8 million higher than the base (normal) case. Given production costs in the NEM at the time were \$1.7 billion, this equated to a 0.47 per cent increase in costs.

Box 18.3 Disorderly bidding in New South Wales on 4 February 2010

Early in the day of 4 February 2010, part of the network in Sydney's Central Business District (CBD) was taken offline for planned maintenance. By mid-morning, potential overloads were identified between the CBD and Sydney South. To remedy these overloads, the line from Kemps Creek to Sydney South was taken out of service at 10.25 am. Flow-on effects through the transmission network then saw flows exceed limits on the Mt Piper to Wallerawang transmission lines (160 kms west of Sydney).

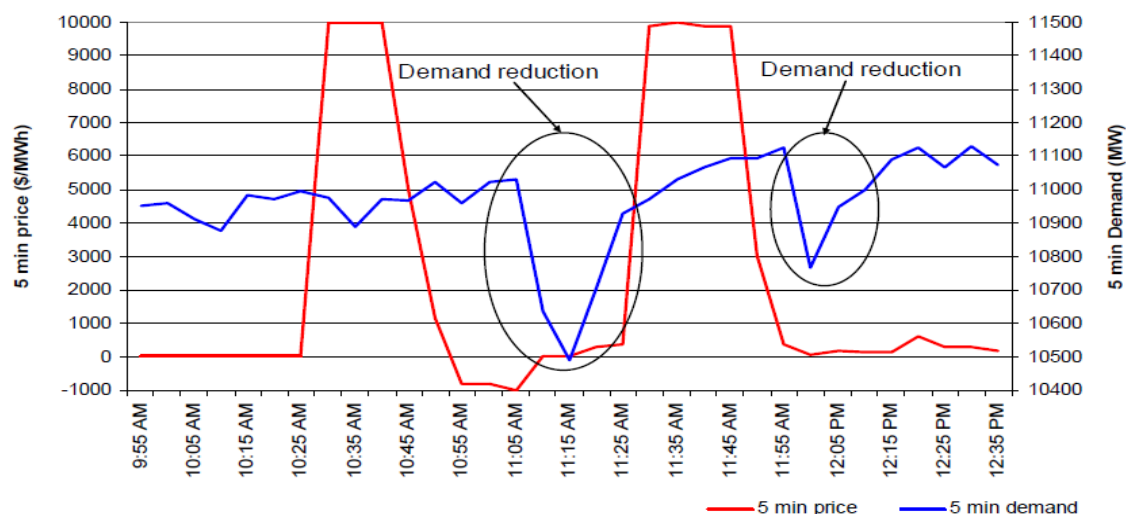
The figure below depicts prices during the morning of these overloads. In the face of the line constraint, the quantity of negative offers from generators increased, from 6200 MW at 10.30 am to 10 600 MW at 10.40 am (New South Wales aggregate demand at the time was just below 11 000 MW). The effects of the constraint set the price to \$10 000 MW/h (the market price cap at the time) for three dispatch intervals from 10.30 am.

The high prices caused an apparent demand response, which saw a 540 MW reduction in New South Wales demand at around 11 am. This, combined with increasing negative offers from generators saw a dramatic drop in the five minute price, to the price floor of -\$1000 at 11.05 am (prices are settled on 30 minute periods, as the average of the 6 intervals, so actual settlement prices did not drop so severely). Following the reduction, demand rose, generators reduced their negative bids, and the price returned to nearly the price cap for four five-minute intervals.

There was another demand response (roughly 350 MW) at 12 pm, leading to a (less dramatic) fall in prices. At 12.40 pm, the Mt Piper transformer returned to service, relaxing the Kemps Creek to Sydney South constraint. As a result, unconstrained generation with a negative bid became marginal, and prices dropped to -\$996 at 12.45 pm.

These constraints also reversed the flow of the interconnectors. QNI was forecast to import 1050 MW into New South Wales, but instead exported 446 MW to Queensland. Similarly, the Vic-NSW interconnector was forecast to import 1135 MW, but the constraint forced flows into Victoria of up to 1301 MW.

Five minute price and demand, NSW, 4 February 2010



Sources: AER (2010d), Lerchbacher (2010) .

Accordingly, generators may locate in the ‘wrong’ places to take advantages of constraints, particularly in relation to interconnectors. There is some evidence that this occurs. The AER has suggested that the Kogan Creek 760 MW capacity coal plant in Queensland was located to take advantage of the revenues created by disorderly bidding. The plant is located between the Queensland/NSW interconnector (QNI) and a congested part of the Queensland transmission network (AER 2010c, p. 12). The AER claimed that increases in output from Kogan Creek from 500 MW to 750 MW decreases power imports across QNI ‘on an almost one for one basis’, to the point that — when Kogan Creek runs at capacity — imports across QNI stop (AER 2010c, p. 13).

Additionally, common ownership of even structurally separated generation and transmission could potentially delay responding to the need for a transmission upgrade.⁹

Finally, the observed flows on an interconnector act as inputs into transmission planning processes. Where flows are artificially reduced by disorderly bidding, forward planning about the need for (or size of) upgrades for interconnectors and intra-regional transmission lines can also be affected.

Overall, while the short-term efficiency effects of disorderly bidding may appear small, the longer-term effects on financial markets, generator location, interconnector flow and planning are of (significantly) greater concern. Given that, there are compelling grounds to ensure that any future framework for transmission planning and pricing addresses disorderly bidding.

18.3 Potential solutions

An efficient solution to disorderly bidding should motivate generators to make bids, or face prices, close to their ‘true’ marginal costs at the point of generation. There are many possible options for achieving this, with tradeoffs between their effectiveness and their ease of implementation.

At one end of the spectrum is the imposition of a formula on generator bids at times of congestion. A simple approach would be to use the historically observed ‘system normal’ bidding behaviour of generators. Alternative methods include de-linking generators’ returns from the regional price in the presence of congestion, for example by making them face their ‘nodal’ (or local) price, potentially packaged with hedging

⁹ As noted in chapter 3, various state governments still have significant common ownership of generation and networks. There is no evidence that they have taken advantage of this.

options.¹⁰ By removing the incentive to bid low in order to maximise dispatch, such imposed formulae can resolve the short-term dispatch efficiency issues caused by disorderly bidding. However, they are not necessarily the best method for dealing with longer-term issues such as generator investment and location.

Alternative approaches taking a long-term view can still realise the short-term benefits of these simple options, but can also more directly influence the timing and, particularly, the location of generator investments, introduce greater market signals to transmission investment and improve the alignment of generation and transmission investment. Improvements in these factors would have subsequent benefits for interconnector use and investment.

Various reviews have canvassed long-run solutions. Of most relevance is the AEMC's current Transmission Frameworks Review (TFR). The TFR examined three aspects of the regulatory framework for transmission: generators' certainty of access to the regional reference price, transmission planning, and arrangements for connecting generators to the network. Of these, the options for generator access are relevant to disorderly bidding issues.

In the First Interim Report (AEMC 2011f), the AEMC contemplated five packages for reform of generator access to the network.¹¹ In the Second Interim Report (AEMC 2012j), the AEMC focussed on two options:

- Optional firm access (OFA): in which generators can purchase from a Transmission Network Service Provider (TNSP) a privileged financial right to a given amount of the capacity of a transmission network ('firm' access). The generator does not have to actually dispatch power, but any other generator displacing the purchased capacity must pay the generator that has acquired firm access. Accordingly, firm access provides firm *financial* access (as distinct from physical access) to the regional reference price through a compensation mechanism.
- Non-firm access — effectively the status quo. It would not prevent disorderly bidding and its associated significant problems.

¹⁰ For example, package 2 of the AEMC's First Interim Transmission Framework Review divides generators' returns into two components: energy payments settled at the marginal price at their local node, and a hedging element that divides the total *intra*-regional settlement residue between generators according to capacity, not dispatch.

¹¹ These five packages were: a minor clarification to the status quo, a 'shared access congestion pricing' mechanism that would effectively impose congestion pricing at times of constraint, introducing transmission reliability standards for generators, an option to allow generators to purchase 'firm' access along transmission lines, and locational marginal pricing for generators (but not load).

Of these, only the first (optional firm access) can address the long-run inefficiencies due to disorderly bidding, and is the Commission's preferred option.

An optional firm access reform package

The OFA package proposed by the AEMC is a complex and integrated package that aims to address several key issues, including disorderly bidding, dispatch certainty for generators, locational signals for generators and the lack of market signals for transmission operation and planning.

The key features of the AEMC's package (AEMC 2012j, pp. 22–23) are:

- *Purchasing firm access:* generators would have the option of purchasing a quantity of 'firm' access from TNSPs, or leaving all (or part) of their output subject to non-firm access.
- *Access pricing:* there would be no charge for non-firm access, but firm generators would pay TNSPs a charge reflecting the long-term incremental costs (LRIC) of increasing the network capacity over time. LRIC is a particular form of the broader principle of long run marginal cost (Marsden Jacob Associates 2004).¹²
- *Firm access standard:* TNSPs would be required to plan and operate their network to provide a level of capacity necessary to meet the purchased levels of firm access (analogous to customer reliability standards, but targeting outcomes that matter for firm generators).
- *Access settlement:* where non-firm generators are dispatched ahead of firm generators, they are liable to compensate firm generators for any loss of dispatch. In this manner, 'firm' access refers to certainty of financial return, rather than physical dispatch. This settlement process affects generator bidding behaviour in a similar manner to congestion management mechanisms, and reduces incentives to disorderly bid.¹³
- *Inter-regional access:* Generators and retailers could purchase firm inter-regional access rights for a given amount of capacity on interconnectors. These

¹² For the purposes of implementing the OFA package, the AEMC examined specific pricing methods. They defined LRIC and LRMC as different methods. In the technical appendix to the Second Interim Report of the TFR (AEMC 2012n, pp. 42–43) the AEMC discussed the relationship between their definitions of the two measures (as well as 'deep connection charging').

¹³ In particular, the settlement mechanism has a similar effect to the 'Shared Access Congestion Pricing model ('package 2' from the TFR First Interim Report).

purchases (combined with bids from other beneficiaries) would be used to direct and fund future interconnector expansions (this element of the package is discussed further in chapter 20).

The package also requires additional regulation of TNSPs as the monopoly providers of firm access. This regulation would include (AEMC 2012j, pp. 35–7):

- requirements to provide information to generators requesting firm access in a timely manner, and to negotiate in good faith.
- transparency of any approved LRIC pricing methodology.
- changes to revenue regulation. TNSP revenue from firm access sales would not be capped, but the prices for firm access would be regulated (to ensure the methodology used was consistent with LRIC). Instead, an estimate of the expected revenue from firm access charges would be ‘carved out’ from total revenue requirements, leaving the remainder of the revenue cap to be spread across users of load services through transmission use of system charges
- quality regulation in the form of financial incentives that penalise TNSPs for shortfalls in providing the subscribed levels of firm access. These financial penalties would be transferred to affected generators through the access settlement process.

The AEMC’s optional firm access package also includes a lengthy transition process that calculates generators’ access requirements, scales them back to the existing capacity of the shared network, and gifts generators with (temporary) firm access based on their past use. These transitional access rights would be removed progressively over a period of up to five years, or over at least the remainder of the existing regulatory determination period (AEMC 2012j, p. 39). During the transition phase, TNSPs would also be exempt from financial quality incentives.

Sudden changes in regulation can create uncertainty and confusion amongst stakeholders, particularly in the case of a complex reform to an already complex area, such as electricity. The approach suggested by the AEMC aims for a smooth transition by phasing in changes through endowing generators with initial firm access rights. This would allow generators (and TNSPs) to ‘learn’ and become accustomed to the reforms over time. On the other hand, providing all generators with an endowment based on existing use could simply delay the benefits of optional firm access and (temporarily) create a more complicated version of the status quo (with no relativity in access pricing to induce changed investment decisions by generators). Given the extent of consultation through both the Commission and the AEMC’s process, there may be scope to shorten this transition period in order to access the benefits from reform sooner (or, given that take up of

the reform is optional for generators, another option would be to simply pre-announce the changes in advance of implementation).

While the OFA package is wide-ranging, its most important elements are the access settlement process, and the ability to pay for firm access (on both intra- and inter-regional lines).

The access settlement process — a congestion management mechanism

The access settlement component addresses transmission congestion. Through a series of complex formulae (AEMC 2012n, pp. 103), the access settlement process provides compensation to firm generators who were not dispatched due to congestion. The compensation is paid by the (generally) non-firm generators who contributed to the congestion. This settlement process is a transfer between generators that operate separately from the market dispatch process (which would continue to function as it does now). As such, the settlement process does not increase the total price the wholesale market pays for electricity. In fact, it is designed to address disorderly bidding and encourage generators to bid at their marginal costs, reducing overall costs.

The compensation for generators takes the form of the ‘flowgate price’ for each MW of firm power that is not dispatched.¹⁴ The flowgate price is the marginal benefit of relaxing a constraint affecting the flowgate.¹⁵ This is equal to the amount that the market currently pays for that marginal MW (the regional reference price) less the cost of a ‘cheaper’ MW that could be accessed from the generators using the constrained flowgate (the locational marginal price of the affected generators). Where a firm generator is the marginal generator at its node, and enters a bid equal to its marginal cost, the flowgate price will be the same as the profit margin that the constrained firm generator would receive from dispatching that MW. Therefore, firm generators’ profits are the same regardless of whether they are dispatched or not, eliminating any incentive for firm generators to enter disorderly bids.

¹⁴ That is, the difference between a generator’s ‘entitlement’ (or access right) and their ‘use’ (or quantity dispatched).

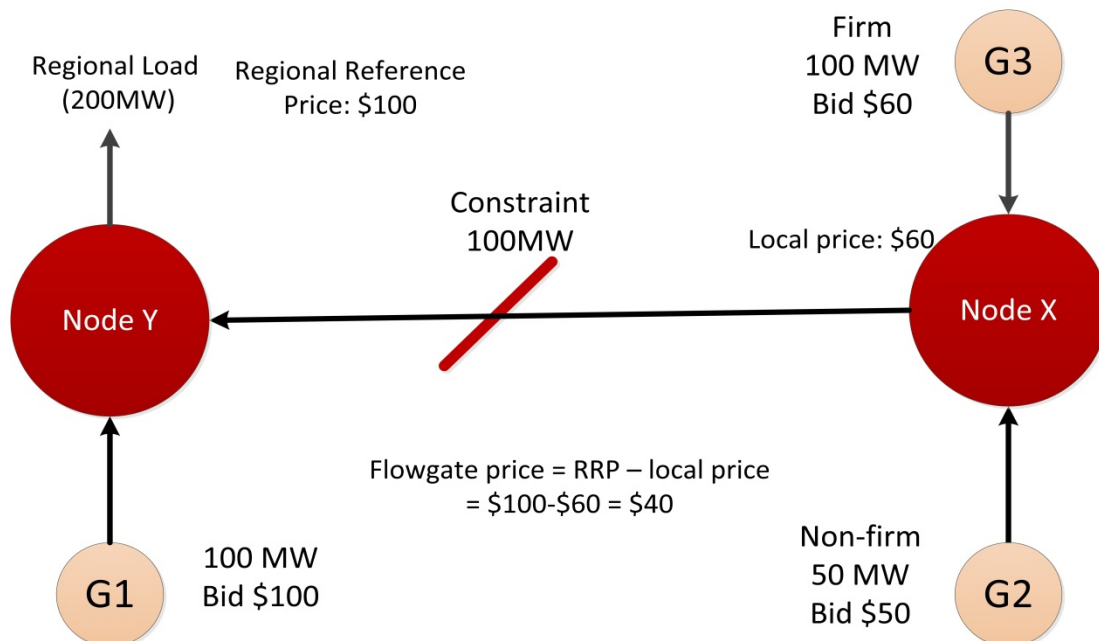
¹⁵ A ‘flowgate’ is a location on the shared network where congestion can occur (effectively, a transmission line between nodes). When congestion arises, these lines become bottlenecks in the transmission network. The AEMC (2012n, p. 99) define flowgate capacity as a combination of transmission line capacity and local demand (to the extent that it participates on a given flowgate).

Conversely, other generators must pay compensation equal to the flowgate price for each MW where their dispatch amount exceeds their own firm access entitlement (which may be zero). If a non-firm generator entered a disorderly bid, they would still receive the regional reference price, but would incur their costs for units produced, and would also be liable to pay compensation through the settlement process. This would lead to losses and therefore remove the incentive for disorderly despatch. Where the non-firm generator is more efficient than a firm one, they would still pay compensation, but should still profit from being dispatched (box 18.4).

Where a given flowgate (or indeed, the entire NEM) was used by only non-firm generators, their entitlements would be a proportion of the available transmission capacity, based on their available generation capacity. So, if two generators of 600 MW and 400 MW capacity sought to use a transmission line of 500 MW capacity, their respective ‘entitlements’ would be 300 MW and 200 MW. The degree (and direction) of compensation flowing between non-firm generators would be determined by the difference between this (implied) entitlement and the dispatch amount for a given generator.

For a non-firm generator to make a contribution to profit from being dispatched, rather than staying idle (and regardless of the presence of any firm generators), its marginal cost must be less than the locational marginal price. In this way, the access settlement mechanism ensures that, even in the presence of congestion, generators have an incentive to bid in a manner that reveals their true marginal costs. As such, adoption of the OFA package would ensure that, at the very least, a congestion management mechanism would apply in the NEM. This element alone should address disorderly bidding and provide (at least short-term) benefits.

Box 18.4 The access settlement process



If the line between node X and node Y is constrained, the combined dispatch of G2 and G3 cannot be more than 100 MW. With a lower bid, the non-firm generator (G2) is dispatched ahead of the firm generator (G3), constraining G3 off by 50 MW.

Dispatch and energy settlement occurs as it does currently, with the regional reference price set at \$100 by the marginal G1, who dispatches 100 MW, and receives \$10 000. G2 dispatches 50 MW for \$5000 and G3 50 MW for \$5000, for a total of \$20 000.

Given G2's usage of the constrained flowgate (50 MW) exceeds its entitlement (0 MW), it will be required to pay compensation in the *access settlement* process (separately from *energy settlement*). As G3's usage (50 MW) was below its entitlement (100 MW), it will receive compensation, calculated as entitlement minus usage, multiplied by the flowgate price (\$40). After compensation, the generators' revenues are:

- G1 is not affected by the constraint, so it receives only the energy settlement: \$10 000
- G2: receives energy settlement, *minus* compensation: $\$5000 - 50 \times \$40 = \$3000$
- G3 receives energy settlement *plus* compensation: $\$5000 + 50 \times \$40 = \$7000$

Assuming G3's bid is its marginal cost, if it was dispatched for the extra 50 MW, it would have received \$5000 more, but incurred costs of \$3000, for additional profits of \$2000. So the compensation has put G3 in the same financial position as if it were dispatched.

G2's incentives depend upon its marginal costs. If its costs are below the local price (\$60), then it will profit. If its costs are \$60 per MW, it will be indifferent. If its costs are higher than the local price (say \$70 per MW), but it bids below the local price, it will be dispatched (and receive \$5000), incur production costs (\$3500) and owe compensation (\$2000), resulting in an overall loss (-\$500). In this way, the access settlement process discourages disorderly bidding.

Source: adapted from AEMC (2012j).

Procuring firm access — a long-term signal

Under the OFA package, the ability of generators (and in the case of regulated interconnectors, retailers) to purchase a quantity of firm access from TNSPs would operate as a two-way signal.

For transmission companies, the signals are firm access requests by generators. This creates ‘market-driven’ signals for transmission investment because generators in a competitive environment seek investment to meet their needs. It avoids sole reliance on planning by a TNSP. This should lead to a better alignment of transmission investment with generation needs. Further, procurement of large quantities of lines by generators is less of a social concern than any potential ‘gold-plating’ by TNSPs under the current economic regulatory regime. As generators generally operate in a workably competitive market, any incorrect decisions to procure firm access will result in fixed costs that are not fully recouped through the wholesale market, with the loss being borne by generation owners, rather than spread across all users through increased transmission charges.¹⁶ Thus, those making the decision would bear the risk. Similar benefits would arise from generators and retailers being able to purchase firm access across interconnectors.

For generators, the prices charged by TNSPs for firm access act as the market signal. Provided regulation prevents TNSPs from using their monopoly position to increase charges, prices should reflect the net present value of the LRIC of providing the requested capacity. The use of the LRIC should provide two important signals (AEMC 2012j, p. 32):

- *locational*: as longer transmission lines would need to be built, generators in remote locations would pay a higher price than those close to loads (or the RRN)
- *congestion*: where a generator located in a congested part of the network, and requested firm access, expansion of transmission lines would be immediately required for the TNSP to provide the requested firm access. Where a generator located in an area of substantial spare transmission capacity and sought firm access, any necessary investment would be a long way into the future. As such,

¹⁶ To the extent that the generation market is not fully competitive, there is also the possibility of the reverse case — that is, generators passing on, at least partially, the costs to energy users through increased wholesale prices. Where this constitutes a misuse of market power, it is a matter of competition regulation, which to date has found it difficult to detect and prove such offences. Nonetheless, the congestion management aspects of the proposed OFA model should at least cut off disorderly bidding as one avenue for using market power.

the net present cost of locating in an uncongested area would be lower than in a congested area, as the transmission investment needed to meet access requests would not be required for some time into the future.

Cost-reflective pricing of firm access ensures that location and congestion would be one element of the overall decision to invest in new generation. Other factors, such as proximity to natural resources or load (demand centres), may often be more important. Consequently, generators could still choose to locate in relatively congested areas. The difference is that, under the OFA package (through both access pricing and the settlement mechanism), the generator should have considered all the appropriate costs and made a decision that is, overall, an efficient one.

Optional firm access and transmission planning — complements or substitutes?

The network transports power from generators to load centres. Under the OFA package, the generation side of transmission investment is driven by the market signals described above. This raises the issue of how OFA interacts with, or indeed if it replaces, transmission planning arrangements.

While the introduction of market signals would improve the coordination of generation and transmission investment, it would not necessarily result in optimal network development. For it to do so would assume that users' interests directly aligned with suppliers', and that generators are motivated to demand transmission investment at the right place, and at the right time, for consumers.

Although markets within the NEM can achieve impressive feats of coordination, their present structure does not result in a complete alignment of generator and user interests in terms of transmission investment. For example, generators' financial interests rely on delivering power to a regional reference node. As such, their firm access requests will relate to lines between generators and the RRN. Load centres that require transmission from the RRN with little to no local generation may be under-provided if transmission investment were solely directed by generators.

In the future, were the demand side able to obtain firm access (through for example, retailers requesting access), these concerns could be alleviated as transmission could be more directly driven by consumer need. However, in order to do so, customers would need to (at least partly) face cost-reflective prices. Given the NEM-wide rollout of smart meters could take a considerable time (chapter 11), retailers would not see any degree of efficient response to price changes (in timing or quantity of use) for some time. Consequently, any signals they would be able to send through purchasing firm access would also be distorted.

Further, even in the presence of (undistorted) signals from both sides of the market, there is likely to be a role for some independent oversight of the planning of the transmission network (whether it be the current system, the hybrid system currently favoured by the AEMC, or a NEM-wide planner as recommended by the Commission in chapter 15).

As discussed in chapter 15, it is difficult to correctly align the incentives of private actors (with limited liability) with potential high impact, low probability events. While generators (and retailers) would have some incentive to avoid such catastrophes, they would not bear the full costs of protracted and widespread blackouts (if, say, transmission lines to Melbourne or Sydney were to go down for an extended period). Given the possibility of such extreme consequences, and the inability with transmission to be able to confidently use lead indicators to monitor the reliability of the network, some planning oversight would still be necessary over the long-run.

There would also be precautionary grounds for detailed planning and identification of constrained transmission lines for at least an interim period. While it appears to be elegant and theoretically sound, OFA may not work perfectly, and, if implemented, should be evaluated before contemplating the removal of the role of detailed independent planning. The Commission also notes that even systems in the United States that use full nodal pricing retain at least some role for a regional transmission planner (chapter 15).

However, having both transmission planning and OFA mutes the benefits available from each. For planning, any benefits available from improved coordination would only apply to a subset of the network, as transmission investment for generation would be market-driven. For the OFA package, the presence of lines built to meet reliability standards introduces complications. While there may be some radial lines in the NEM that carry power solely to a load, or some that only serve generators without load centres, the bulk of lines will serve both generation and load. As such, it may be possible for some generators to ‘free ride’ on the capacity that is built for (and paid for directly by) load. Indeed, the OFA package contemplates a mix of firm (that is, paid) and non-firm generators.

Not all generators would free-ride. Peaking generators that depend on access to the RRN at peak times would still have strong incentives to purchase firm access. However, some baseload generators that rely on average returns may have incentives to stay non-firm and operate on the planned network. As the AEMC (2012n, p. 87) note, given the presence of excess generation capacity, not all non-firm generation would need to be accounted for in building the network to meet

peak demand. This would make free riding on ‘reliability’ lines a somewhat risky proposition.¹⁷

Another source of risk for non-firm generators, even in areas of excess transmission capacity, would be the potential for entry by new generators. In uncongested areas, a new entrant could receive firm access for a relatively low price. A new, firm, entrant would not only reduce the non-firm incumbent generator’s energy market returns in the short-term, but would also increase the cost of any future firm access that incumbent may wish to purchase (as that access would now require more immediate additional transmission investment, increasing the LRIC). To prevent this, the non-firm incumbent would have an incentive to pre-emptively purchase firm access as a ‘defence’ against new firm entrants, further reducing the extent of free riding.

Nevertheless, while some free riding could erode the benefits of the OFA package, particularly in relation to generator location signals, it is unlikely to eliminate them. For instance, the benefits from addressing disorderly bidding would remain.

The degree of free riding also depends on the type of planning model that overlays on OFA. As noted in chapter 15, the adoption of the AEMC’s hybrid model would probably result in, on average, higher reliability standard than the NEM-wide probabilistic model advocated by the Commission. All other things equal, the hybrid model would result in more transmission investment for load purposes, and thus perhaps more free riding.

Further, a NEM-wide planner would be able to oversight firm access requests across the NEM, alleviating concerns of monopoly pricing, and reducing the reliance on regulation of TNSPs. At the least, an independent planner could be an additional source of information for generators, limiting the ability of TNSPs to price above cost.

Overall, the Commission considers that the benefits of the OFA package would still be significant even in the presence of transmission planning.

The way forward

Disorderly bidding and the (lack of appropriate) long-term investment signals for generators contribute to congestion, affect the optimal use of interconnectors and

¹⁷ The AEMC (2012n, p. 87) also note that, given TNSPs should meet reliability requirements with least-cost builds, they are likely to build (or augment) lines to generators close to the RRN. This makes generators remote from the RRN much less likely to free ride than those close to it.

planning for any future interconnector upgrades. If these issues were not resolved, the benefits from any further investment in interconnection would be muted at best, as generators have strategic incentives that can, under certain circumstances, frustrate the use of interconnectors. Accordingly, the Commission considers that reform is warranted.

The key to any solution is mechanisms that reveal the true cost (including congestion) of generators bidding into the NEM. Changes in the Rules that remove the current perverse bidding incentives of generators would better manage congestion and remove the current distortions that lead to underutilisation of interconnectors. Upgrading interconnectors would make little sense until these underlying incentives were addressed.

While short-term solutions such as the imposition of congestion management formulae on bidding would be beneficial, the Commission favours the OFA package option in the AEMC's Second Interim Report of the Transmission Frameworks Review, because it creates better market signals for generator location and transmission investment. While conceptually complex, the information to implement it is already available and so its implementation should not face many practical obstacles. The implementation of OFA transfers rents from some generators, but that does not involve any inefficiency, and in any case, the existing system leads to transfers that are arguably less defensible.

Although it removes the incentive to disorderly bid, optional firm access implements new pricing arrangements, and could create new incentives for participants to 'game' the system in different ways. It would therefore be prudent to monitor generator bidding behaviour to observe if any new patterns emerged. This could inform any 'fine tuning' that the system may require at a later date.

DRAFT RECOMMENDATION 18.1

In the absence of any unintended consequences identified during current consultation processes, the Australian Energy Market Commission's 'optional firm access' package for generator access to the transmission network should be implemented.

- ***It should operate for a period of at least 10 years.***
- ***It should be monitored by the Australian Energy Market Operator for its effects on network planning and performance and, in concert with the Australian Energy Regulator, changes in observed patterns of generator bidding behaviour. Monitoring results should be made public annually.***

While optional firm access appears to be beneficial, it is not necessarily the end-point for market reform in the NEM. Over the longer-term, there may be grounds for more fundamental reform.

18.4 More fundamental reforms

Nodal pricing — theory

Optional firm access is an effective way of resolving perverse incentives that arise in the presence of congestion, but it does so by using the existing regional settlement method and essentially ‘retro-fitting’ side compensation payments. A more direct method of managing congestion would be to dispatch and pay generators according to their locational marginal price (LMP), not a regional price. The price of electricity at different locations where electricity is injected or withdrawn from the network (‘nodes’) would differ (a model also referred to as ‘nodal pricing’), especially in the presence of congestion on particular lines.

In addition to exposing generators to the ‘true price’ (encompassing production, location and congestion costs) at their connection point, nodal markets also generally involve a system of ‘financial transmission rights’ (FTRs), that operate in a similar manner to optional firm access rights (typically defined on either a point-to-point, or ‘flowgate’ basis). In effect, FTRs provide access to the local price at the ‘destination’ node, acting as a form of hedge between nodes. Importantly, these rights can be purchased, typically at auction, on a ‘directional’ basis (that is, ‘A to B’ is a separate right from ‘B to A’). The rights can be purchased by both users and producers. In the same way as firm access rights, the auction of FTRs could provide a market-driven signal for transmission investment from *both* supply and demand sides of the electricity market, aligning transmission investment with its value to users.

Several electricity markets around the world use such nodal pricing, but the exact model applied varies between markets. For example, both the Pennsylvania-New Jersey-Maryland (‘PJM’) in the United States and the New Zealand electricity market use ‘full nodal pricing’, that is both generation and load are settled at nodal prices.¹⁸ Alternative models include ‘generator nodal pricing’ where generators are

¹⁸ But these markets differ in other respects. For example, in the PJM market, ‘point-to-point’ FTRs were introduced when the market commenced (Frontier Economics 2009). In New Zealand, the market commenced in 1996 and FTRs have been the subject of much debate and analysis since then, without being implemented. Following a more recent consultation process,

settled using granular locational based pricing, but loads are settled using more aggregate prices (for example, prices for a zone or region, or a single price for the entire system). One example of this is the New York electricity market in the United States, where generators are settled on a ‘location-based’ marginal price (similar to LMPs), and loads are settled on a zonal basis, using a load-weighted average of the prices within their zone (Frontier Economics 2009, p. 39).

While the increased granularity of nodal pricing encourages more efficient dispatch (by removing incentives for behaviour such as disorderly bidding), it can in turn facilitate other forms of inefficient behaviour. In nodal markets this typically manifests itself as more traditional uses of market power, with generators withholding supply in order to increase their LMP. This is one of the reasons why some nodal markets include measures designed to encourage levels of supply, while inhibiting the ability of generators to exercise market power. For example, the PJM market incorporates:

- an *offer cap* to prevent large spikes in prices. These are set at \$1000 per MWh by the Federal Energy Regulatory Commission. (The presence of capacity markets in the United States is intended to provide a means for generators to recover fixed costs, while energy market returns recover variable costs. In contrast, in the Australian NEM, the high price cap in the energy market is intended to allow generators to recover both fixed and variable costs.)
- *market power mitigation rules* designed to prevent the use of local (or time-limited) market power. These rules entail capping of generators’ offers, typically applying a formula based on generator-specific cost-based schedules (Hogan 2012b). In some markets, the trigger for application of these rules has been refined over the years to concentrate on those generators and bids that would have a significant impact on the market (Frontier Economics 2009).

Despite the concerns of the structural presence of market power, there has been little evidence of the exercise of market power in the major nodal markets to date (Frontier Economics 2009, Rose 2011). This suggests that the combination of capacity markets and mitigation rules has had some effect in limiting the ability of suppliers to take advantage of their positions of market power.

Nodal pricing is the subject of significant academic and regulatory analysis — more detail on the theory of nodal pricing, and particularly its application in a variety of markets can be found in Frontier Economics (2009) and NWRED (2011), among other sources.

the New Zealand Electricity Authority (2012) expects the first auction of inter-island FTRs to be in early May 2013.

Nodal pricing in Australia?

Nodal pricing in the NEM was proposed in a major review 10 years ago (Parer 2002). However, it has not been adopted due to its complexity, perceived difficulties in implementation and potential increases in risk in financial markets. Perceived political difficulties with exposing customers within the same region of the NEM to different energy prices have also been an obstacle. There have also been concerns that the ‘geography’ of the NEM is not as suited to nodal pricing as some other networks are. For example, PJM is a highly meshed network, and as such there is potential for congestion on a single line to have wide-reaching effects. In comparison, the NEM is a more ‘stringy’ (or radial) network where distance looms as a larger issue than congestion. While nodal pricing may have particular benefits for networks such as PJM, it would nonetheless provide benefits for the NEM, both in terms of dealing with congestion,¹⁹ and properly accounting for location.²⁰

In the First Interim Report of the TFR, the AEMC contemplated an option for a form of nodal pricing that included a single national price for customers (box 18.4).

However, the AEMC’s proposed option was not supported by stakeholders in that review who noted that, among other things, a single national price for load would blunt any efficiency gains by rendering the demand side unresponsive to any localised price signals (AEMC 2012j, p. 122). In the Second Interim Report, the AEMC decided against further consideration of the model. It stated that difficulties in creating the single TNSP (that it felt was a necessary component of the model), combined with the efficiency concerns of a single national price for load made the model a ‘disproportionate response’ (p. 123).

If full nodal pricing were to be implemented, the Commission acknowledges that differences in pricing between locations can cause equity concerns. But, as noted elsewhere in this report (chapters 11 and 14 and draft recommendation 11.6), the Commission considers that such concerns should be dealt with by more transparent and targeted assistance for particular customer groups, rather than uniform pricing. Doing so would alleviate distributional concerns, while preserving the efficiency gains available through (cost reflective) price signals. Providing information to

¹⁹ As noted in chapter 17, and above, while congestion is not (currently) prevalent in the NEM, instances of congestion can lead to substantial transfers, and have long-term efficiency effects.

²⁰ As discussed above in relation to the OFA package, it is important that location (including the costs related to distance and the requisite network investment) is considered as part of an overall investment decision for load and generation. In many cases, it may not change the final decision, as proximity to load or resources will often be the deciding factors, but it is nonetheless important that it is included in considerations.

consumers about the nature of the change, the benefits from it, and the options available to them would also be an important precursor to any implementation of nodal pricing.²¹

Box 18.5 The AEMC's National Locational Marginal Pricing

The First Interim Report of the Transmission Framework Review included the option of a 'national locational marginal pricing' (NLMP) package.

In this package, generators would be settled in the energy market using their locational marginal price (LMP). This component of the package would largely remove the incentive to disorderly bid, as generators would no longer be able to enter low bids yet receive the higher regional price.

Generators would then have the option of purchasing (at auction) fully firm financial transmission rights. These rights would provide firm access to a single, national trading hub. This hub would use a single 'system marginal price'. Load (that is, users) would be settled at the system price, not using LMPs. This was intended to provide a deeper and more liquid energy trading market than the present regional system. More broadly, the package would remove the need for 'regions' in the market arrangements.

The AEMC envisaged the implementation of NLMP involving a single, national TNSP. This TNSP would initially auction the baseline transmission capacity, followed by auctions for incremental capacity. It would be exposed to incentives that encouraged the availability of the auctioned transmission capacity. This capacity would be made available by investing in the physical network to ensure that its capacity matched the amounts purchased at auction.

Source: AEMC (2011f).

The substantial difference between the current NEM model and nodal pricing has also raised concerns in the past about the degree of transition costs that could be incurred by moving to nodal pricing. Indeed, the introduction of nodal pricing would require careful establishment of new market infrastructure. This is a particular issue for the hedging markets, and one that must be considered alongside the auctioning of financial transmission rights (FTRs), a significant issue for the New Zealand market. The introduction of nodal pricing would also require consideration of governance issues, particularly if the markets' departure from a regional structure lends further weight to NEM-wide transmission planning.

²¹ The options to consumers would arise through retailers, who could increase their range of tariff offerings by purchasing different bundles of FTRs. This could also allow different retailers to 'specialise' in different types of 'package' such as flat (sourced through FTRs that ensured financial access to baseload generators) or variable (FTRs to a range of generators) pricing.

While transition costs are a relevant consideration for judgements of reform, there are several well-known ways to minimise them by managing the transition process — general options include the pre-announcement of changes, and gradual phasing in of reform. However, given it is a significant shift from the status quo, and a matter of market design, adopting nodal pricing may not be conducive to phasing.

While phasing directly to nodal pricing may not be appropriate, the Commission considers that the OFA package represents a substantial transitional step towards implementing nodal pricing. It involves many of the same (or at least analogous) aspects to nodal pricing — including the calculation of LMPs, a concept of congestion pricing and firm access rights. Thus, allowing the OFA package to operate for a period of 10 years would allow the energy market to acclimatise to many of the complexities that have frustrated the thought of implementing nodal pricing in the past. Similarly, it could also allow hedging markets to adjust to the concept of different prices (for generators).

After that time, a cost-benefit analysis of the introduction of nodal pricing should be conducted, with a view to identifying any significant and insurmountable obstacles that would prevent its adoption. Such an analysis could also consider the exact form of nodal pricing involved, the structure of financial transmission rights (particularly given the evolution of optional firm access requests) and any accompanying market infrastructure that would be required, such as capacity markets or the need for any specific market power controls. At this time, extensive community consultation would also be required.

DRAFT RECOMMENDATION 18.2

After the optional firm access package has been operational for 10 years, a cost-benefit analysis should be conducted, with particular regard to the structure of the National Electricity Market at the time, the views of consumers, and any remaining barriers to the introduction of nodal pricing.

- ***If the analysis finds net benefits are likely, and no significant and insurmountable barriers or risks are identified, nodal pricing (including financial transmission rights) should be introduced with appropriate transitional arrangements and arrangements for disadvantaged consumers.***

18.5 The hedging market

Spot energy market prices in the NEM are highly volatile. This means that any market participant that traded directly through the spot market would be exposed to a significant level of pricing risk. Participants in the NEM manage this risk either by trading in the hedging market (described in appendix C), or through vertical integration with retailers (creating ‘gentailers’). Despite being a purely financial market, outcomes in the hedging market can affect actual energy flows, and particularly the level of interstate trade in electricity.

Hedging markets are state-based

Participants in the hedging market enter contracts based on the NEM’s state based regional reference prices. This allows participants within a region to contract effectively because they are both exposed to the same spot market price. However, if a party wanted to contract with a party in another region of the NEM it would need to bear the risk associated with relative movements in the prices in different states, or alternatively, find a way to manage that risk (box 18.6).

One way to manage this risk is through Settlement Residue Auctions (box 18.7) that allocate inter-regional settlement residues (IRSRs). IRSRs are a financial product that distributes the price residues that occur when electricity is transmitted across a regulated interconnector. However, IRSR’s are a non-firm hedge, which means that if there is a large price separation between two regions and power does not flow through the interconnector, as can occur through disorderly bidding, there is no residue to distribute and the hedging strategy fails.

While it is difficult to know how IRSRs are used by market participants, Anderson et al. (2007, p. 30) suggest that IRSRs are used primarily as speculative instruments, rather than as hedging instruments — contrary to the original intentions of policy makers. (This view was also echoed in comments by participants in the Commission’s consultations.)

Box 18.6 Understanding the risk of trading between regions

A standard hedging product, known as a contract for difference, allows market participants to determine prices in advance and remove the exposure to the spot market. Under such a contract, the generator and the retailer agree to a 'strike' price (shown as X below), which will ultimately be the terms on which they trade, even if the spot price (P) is different.

If the pool price is lower than X (which would expose a generator to losses without hedging), the generator would receive P from the wholesale market and $X - P$ from the retailer, with a net price paid for power of X . If the pool price was above X , the retailer would buy power at P on the wholesale market (that is, would have an apparent exposure of $-P$), but would receive $P - X$ so that the actual exposure would be $-X$. The payoff structure is represented below:

	Spot market exposure	hedging contract	Net exposure
Generator	P	$X - P$	X
Retailer	$-P$	$P - X$	$-X$

However, when trading between regions, the spot price exposures are no longer the same. So, if a retailer (in region 2) buys a hedging contract from a generator in region 1, the payoff becomes:

	Spot market exposure	hedging contract	Net exposure
Generator	P_1	$X - P_1$	X
Retailer	$-P_2$	$P_1 - X$	$-X + (P_1 - P_2)$

$(P_1 - P_2)$ is the risk in relative movement in regional reference prices and is a natural risk of trading between regions of the NEM.

Box 18.7 Settlement Residue Auctions (SRAs)

When electricity flows across a regulated interconnector, loads and generators are settled at their regional price. This means that if electricity flows from a low price region to a high price region (as would usually be expected), the price paid to generators will be less than the price paid by loads. The difference between the two prices, multiplied by the level of flow across the interconnector and after adjusting for transmission losses, is the inter-regional settlement residue.

AEMO sells these residues in a quarterly auction, and the winners of the auction receive the rights to a share of the interregional settlement residues in the upcoming period.

Source: AEMO (2011e).

The average payout of the SRA process corroborates this perspective. Were IRSRs used as a valuable hedging instrument, the auction revenues would be greater than the amounts paid out over the long term because buyers would be willing to pay a premium to manage risk.²² However, the evidence does not support this (table 18.1).

Table 18.1 Historical results of settlement residue auctions

<i>Auction</i>	<i>Residue Distributed</i>	<i>Auction Proceeds</i>	<i>Payout rate</i>
	\$ million	\$ million	%
2009 Q1	83.1	59.1	141
2009 Q2	83.0	15.6	531
2009 Q3	11.5	17.2	67
2009 Q4	145.7	28.0	520
2010 Q1	55.4	55.9	99
2010 Q2	13.9	16.3	85
2010 Q3	20.5	17.5	117
2010 Q4	18.3	32.1	57
2011 Q1	102.1	46.6	219
2011 Q2	6.6	17.6	37
2011 Q3	12.5	21.2	59
2011 Q4	16.4	29.2	56
2012 Q1	7.7	45.5	18
Total	576.7	401.8	144

Source: AEMO Auction Reports (AEMO website).

²² A point made by AEMO (sub. 32, p. 26).

If firms do not use the IRSRs to manage the risk of trading electricity contracts across regional boundaries, they are left with two options. Either they trade across the border exposed to the interregional price separation risk, or they trade only within their state.²³ Of these, the latter is more common, with retailers and generators trading derivative products with other market participants that operate in the same region of the NEM.

Implications of a state-based hedge market

The inability for market participants to effectively trade between regions of the NEM, without being able to manage the risks well, may result in distorted incentives for new generators and large electricity consumers. It may also result in a lack of liquidity in parts of the NEM and may create market power.

Incentives for generator location

The difficulty of trading hedging contracts across regions could distort the locational decisions of new generators and energy consumers. When a generation business chooses a location for a new generator, a key concern will be the availability of well-priced hedges. This consideration will make them more likely to enter a region in which there is more consumption than generation of electricity. This incentive will be in addition to the interplay of supply and demand for electricity. For example, consider a generator that was planning to enter the NEM near the New South Wales-Victoria border. From an engineering perspective, it makes little difference which side of the border they are placed. However, the new generator will look at whether it can trade in forward markets at a higher price in New South Wales or Victoria. A similar situation would occur with large electricity consumers, such as smelters, although access to the hedging market would usually be a lower priority for the locational choices of these parties.

These problems in the hedging market have the potential to equalise the level of electricity generation and consumption in each region of the NEM, as each new generator will favour a location in a region with less generation than consumption, and each new load will favour a region that has more generation. This would result in less interconnector construction and usage than might be efficient. It would also

²³ There is a third option where a firm can hedge using an interregional swap. This involves purchasing a short position in one region and a long position in another, and creates a 'firm' hedge. However, using this as part of a trading strategy across regions is effectively just hedging each individual trade in each region.

make it more difficult for a state to act as a net producer of electricity in the NEM and reduce the benefits from efficient trade across the NEM.

The size of this impact is unclear. The different regions in the NEM are all relatively evenly matched between retail load and generation, which partly reflects history, but also suggests that the incentives described above could be strong. However, there are several other reasons that parties wish to build generation close to a load centre, such as avoiding transmission losses and ensuring a more reliable dispatch.

The Commission seeks participants' views about the extent to which flaws in a state-based hedging market distort the locational incentives of generators and large loads.

Less liquidity in the hedging market

Financial liquidity is measured as the amount of trade that occurs in a particular market. Liquidity is important in a market, as it gives market participants confidence that they will be able to enter and exit contracts in the future. This is particularly important for a new entrant retailer or generator that required some assurance that they would be able to enter hedging positions once they commenced operations.

Higher levels of liquidity also lower the difference between the buying and selling price (bid-ask spreads) of instruments. Bid-ask spreads are a cost of transacting in the market and lowering those spreads results in lower trading costs for market participants.

Some parties suggest that levels of liquidity in the electricity futures market are low, particularly in some regions of the NEM (D-Cypha Trade 2011). However, if the market for electricity hedging products were to become more national, this would allow people to trade across states, and create greater substitutability of contracts in different areas. This would increase the liquidity and improve the performance of the market.

Issues of market power

While generation and retailing are now regarded as workably competitive in most regions of the NEM, market power is not entirely absent in these parts of the electricity system. Market power could arise, for example, if there are barriers to entry for new generators posed by the large scale of cost-efficient generators and a

requirement for high capacity utilisation (which may require the capacity to sell into several regional markets). Box 18.8 sets out some of the claimed forms and impacts of such market power.

Improving the performance of interconnectors and allowing more interstate competition, both in a physical sense and in the hedging market, would further limit the ability of market participants to exercise market power.

There are also grounds for action in one area of (possible) gentailer conduct to reduce market power — while also assisting the RIT-T process. On first appearance, a gentailer has little incentive to exercise market power because high prices at the wholesale level hurt the retail side of their business. However, knowing when a price spike will occur in advance in theory might allow a generator to hedge out of their retail position. Any retail competitors will not know in advance when this might happen and would have to remain hedged against the risk at all times. This might give the gentailer a competitive advantage in the retail sector. This type of behaviour is difficult to detect, as hedging positions are commercial-in-confidence, an issue that has been of some concern in the United States (AEMC 2010b).

Accordingly, there could be some merit, from a regulatory perspective, in providing these hedging positions to the regulator retrospectively, perhaps 12 months after the event, and on a confidential basis. This could allow better examination of market power issues. The regulator could also use the information to publish (aggregated) summary data where this might help potential new entrants evaluate the risks and returns from entry into the generation and retail sectors. This could also have the added benefit of helping market modellers (within either a national planner or TNSPs) understand the incentives behind generator bids, which in turn could improve the accuracy of the RIT-T process.

However, such an improvement in transparency would involve compliance costs on the businesses involved, and risks breaching genuinely confidential contracts. These costs would need to be weighed against the benefits of additional transparency before any transfer of information might be mandated.

Box 18.8 **Market power in generation?**

Residual market power in generation and gentailing could take several forms, although their importance is strongly contested by varying parties. The ACCC has scrutinised the privatisation of New South Wales generation assets (ACCC 2011), AGL's purchase of a larger share of the Loy Yang power plant,²⁴ and whether gentailers are offering power purchase agreements to renewable energy generators (Wroe 2012). The AEMC has also considered issues of market power with regard to rule change proposals. The most recent example of this is the Major Energy Users proposal to restrict the bidding of dominant generators to \$300/MWh. However, in its draft determination, the AEMC (2012o p.49) found insufficient evidence of any problem.

A simple case of market power would occur if a generator had the ability to push up prices in the spot market by withholding supply, and thereby attract more revenue. This would benefit any unhedged generator and adversely affect any unhedged retailer. However, any such market power would likely to be transient, since higher prices would attract entry by competing generators, and empirical analysis by the AEMC has not identified a significant problem (AEMC 2012o, p. i).

A slightly more subtle case of market power would arise if a generator were able to artificially create greater price volatility by withholding some generation capacity, or by bidding into the market at a high price. This might increase spot prices on those occasions, but it could also have an impact on the market for some types of hedging instruments, such as price caps. If that generator had some advantages in selling these instruments,²⁵ such as a gas or hydro plant, they would acquire a return that would not be shared by other generators.

Competition benefits, which are the benefits from reducing market power, are also considered in the transmission planning and RIT-T processes.

The exercise of any market power by generators may have several efficiency costs:

- inefficient merit order dispatch would occur if large low cost generators bidding high were dispatched after peaking generators
- demand side responses may be used inefficiently as the cost of a demand response is typically high compared to the cost of generating energy
- market power may limit the competitiveness of the retail market. Some consequences of this are found in chapter 12
- if market power results in high prices in a region where there is no shortage of supply, it may give incentives for new entrants where none are needed.

²⁴ *Australian Gas Light Company v Australian Competition & Consumer Commission (No 3)* [2003] FCA 1525

²⁵ A discussion of the types of hedging contracts that different generators tend to trade can be found in appendix C.

Options for reform

A more national hedging market would allow for improved risk pooling, enable an efficient spread of generation and load across the NEM and more competition in the generation and retail sectors. The best way to achieve this is to improve the effectiveness of IRSRs.

The AEMC's OFA package includes the option to purchase firm interregional transmission rights. These rights would replace the existing IRSRs and could be used to hedge across regions, with two additional advantages. The access rights would be firmer than under the existing arrangements, making them more likely to be valuable in a hedging portfolio.²⁶ In addition, the OFA structure nullifies incentives for disorderly bidding, and this would also make the hedging instrument more valuable. The OFA model would link the sale of these transmission rights to the incentives to build new interconnector projects.

Another reform option would be to alter settlement residue auctions so that the hedging instrument would pay the difference in the state prices regardless of the actual flow across the interconnector, which is ideal for the parties wishing to hedge. The Parer Review (2002) and the Energy Reform Implementation Group (2007) both suggested variations of this option.

However, the success of this approach would need to overcome several issues:

- As electricity does not always flow between regions when there is a price difference, there may be insufficient revenue to pay parties that purchased the transmission rights. This would require drawing additional funding from elsewhere in the network.
- This approach would become complicated if the parties that can cause counter price flows along a transmission line near some congestion (such as generators near a state border) were also bidding into the auction.

The OFA is the superior option since it addresses many other issues apart from flaws in hedging arrangements. If OFA is not implemented, then there are grounds for amending settlement residue auctions as a second-best option.

²⁶ Though firmer than the current IRSRs, the inter-regional rights under the OFA package are not fully firm, as they would be 'shaped back' (proportionately scaled down) under certain circumstances.

19 Identifying future transmission investment

Key points

- Beyond incentive regulation and reliability standards, there are two principal regulatory influences on transmission investment — the transmission planning process and the Regulatory Investment Test for Transmission (RIT-T).
- Despite interconnection between regions in the NEM, transmission planning is currently conducted at a jurisdictional level.
- More inter-jurisdictional coordination in transmission planning is needed. The potential bias against interconnection between regions was one factor influencing the Commission's recommendation in regard to a NEM-wide planner.
- The RIT-T is a cost benefit test that is performed before major new transmission projects are commenced. While a useful tool, it has some shortcomings.
- There is inevitably scope for those conducting the RIT-T, or any cost-benefit test, to influence the outcome of the test. Currently, the party that performs the test can have financial incentives to achieve a particular outcome. There is no independent approval of the RIT-T.
 - An independent planner should perform the test in a transparent manner.
- The test only allows consideration of costs and benefits that accrue to those who produce, consume or transport electricity.
 - However, there are both theoretical and pragmatic reasons for not expanding the framework to include costs and benefits to other parties.
- The current RIT-T is less demanding for projects justified on reliability grounds than for those done for market benefit reasons. Interconnectors do not have reliability standards, so this differential treatment can create a bias away from interconnector investment.
 - The differential treatment for reliability-based investment in the RIT-T should be removed, with reliability instead considered as a component of overall benefits.
- Due to computational difficulties, it is unlikely that the current RIT-T process will fully capture competition benefits accruing from a new investment. Given interconnectors foster inter-regional competition, this is another potential source of bias away from such investment.
- The current RIT-T framework has the ability to adequately capture future scenarios.

While incentive regulation of the Transmission Network Service Providers (TNSPs) (chapter 5) and the reliability standards with which they must comply (chapter 15) are major drivers of their investment decisions, two other regulatory processes can have a significant influence on the choice of transmission projects. First is the broad planning process, conducted at both a national and jurisdiction level for forward investment plans. Second is the Regulatory Investment Test for Transmission (RIT-T), which is a cost-benefit test applied to specific major transmission projects.

In concert, the goal of these two processes is to identify the most beneficial options for future transmission investment. While such a succinct aspirational statement may seem simple, it belies several complexities. Beneficial to whom? Which benefits can be counted, and how? As the subsequent discussion illustrates, such considerations are highly relevant in assessing the contribution that planning and the RIT-T can make to achieving efficient levels of transmission and interconnector investment in the National Electricity Market (NEM).

19.1 Transmission planning in context

As noted above, transmission planning and the RIT-T are not the only influences on transmission investment decisions — they exist within a complex regulatory system, which brings a range of incentives to bear on TNSP decisions. Other parts of the regulatory system with substantial effects on network investment outcomes include the incentive regulation (chapter 5), the ownership and governance of TNSPs (chapter 7) and reliability standards (chapters 14 and 15).

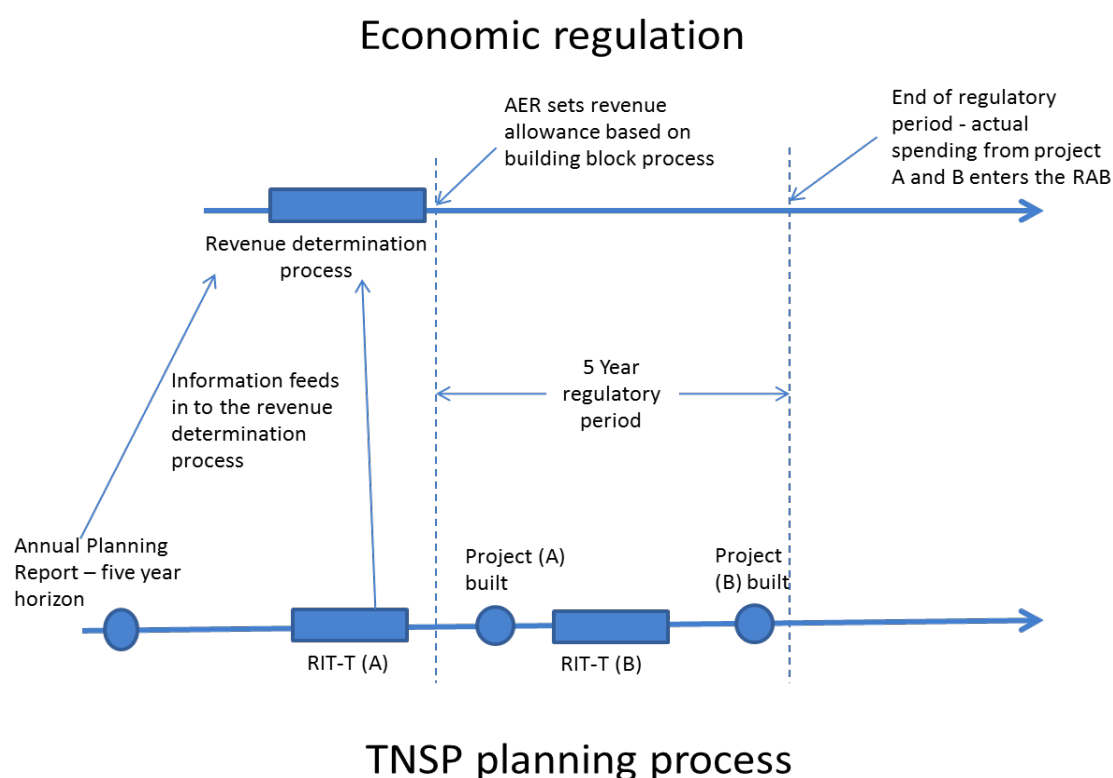
While reliability standards ‘set the goalposts’ for transmission planning, and governance structures are a constant in the background, the interaction between planning (including the RIT-T) and economic regulation is less straightforward. Figure 19.1 below represents this interaction (for jurisdictions other than Victoria).

The economic regulation is centred on the revenue determination process, calculated using the building block methodology. The outcome of the determination is an overall estimate of the efficient cost of operating a network over the upcoming regulatory period. It sets a ‘pool’ of allowed revenue for the TNSP, but does not require that any particular project is built.

As shown in the figure, information from the planning processes (which include Annual Planning Reports and the Regulatory Investment Test For Transmission) feed in to the revenue determination process, but this is only used to inform the process, and is not used in a way that ‘locks in’ any particular investment. In the example below, information from the RIT-T for project A (which is due to be built

in the regulatory period) is available to be used as an input for the revenue determination. It is not possible to use information from RIT-T (B) as it has not been prepared at the time of the determination. Instead, the Annual Planning Report would identify a network need, and an estimate of an efficient manner of addressing the need would be included as part of the overall figure set by the revenue determination. This estimate does not have to match the option that is eventually built, or indeed any of the options considered as part of the RIT-T. At the end of the regulatory period, it is the actual spending — rather than that predicted by the RIT-T or the planning report — that is entered into the regulatory asset base for the next revenue determination. Indeed, neither the RIT-T, nor the planning process, directly determine the funds allocated to a TNSP.

Figure 19.1 **Parallel processes — economic regulation and planning**



^a Based on AER (pers. comm., 20 September 2012).

19.2 Transmission planning

Transmission planning is a forward-looking process that identifies the investments required to: address (emerging) constraints; meet reliability standards; and provide net market benefits. As discussed in chapter 17, constraints within a region in the NEM can have a significant inter-regional effect. It follows that planning of intra-regional transmission can be just as important to the overall level of interconnection as the planning of interconnectors themselves. Further, given the presence of ‘network effects’ (chapter 15) between regions, at least some level of coordination is required to ensure that the NEM is planned efficiently.

Electricity markets originated as a state responsibility and hence transmission planning and reliability standards have developed on a jurisdictional basis (chapter 15). A degree of coordination has been progressively introduced.

Current transmission planning

Jurisdictional transmission planning

The planning on transmission networks in each region of the NEM is undertaken by the local transmission network business, with the exception of Victoria, where AEMO performs this role instead of the TNSP.

The planners are required to publish Annual Planning Reports (APRs) which contain detailed analysis of the planned transmission network over a five year horizon.

The APRs are not developed in isolation, and are required to take into account the National Transmission Network Development Plan (NTNDP), prepared annually by AEMO. Specifically, the National Electricity Rules (NER)¹ stipulate that APRs must ‘set out’:

... the manner in which the proposed augmentations relate to the most recent NTNDP and the development strategies for current or potential national transmission flow paths that are specified in that NTNDP.

¹ Clause 5.6.2A(b)(5). Where a party has not complied with this clause, the Australian Energy Regulator may apply for a court order under s61(1) of the National Electricity Law declaring a breach and require that the relevant party cease the act constituting breach, and/or take action to remedy it (among other things).

Strictly, this only requires that the TNSPs publicly describe the extent of any deviation from the NTNDP, bringing (a degree of) transparency to the interaction between jurisdictional and NEM-wide planning.

In preparing the plans, each TNSP is required to conduct an annual planning review with distribution companies connected to their network. This review must ‘take into account’ the NTNDP (failure to do so incurs a financial penalty).² Importantly, while TNSPs are obliged to consider the NTNDP, the final decision for planning matters rests with each individual network service provider.³

National transmission planning

As noted, in its role as the National Transmission Planner, AEMO annually publishes the NTNDP (AEMO 2011d). In contrast to the detailed, local planning, of the APRs, the NTNDP is intended to provide a ‘strategic’ and national outlook, over a 20 year horizon.

Mirroring the requirements on TNSPs, in preparing the NTNDP, AEMO must ‘have regard to’, among others things, the most recent APRs, as well as the revenue determinations for the TNSPs.⁴ This repeated cross-referencing of the APRs and the NTNDP is intended to provide a transparent ‘feedback loop’ which should, in theory, iterate towards alignment between the levels of planning.

However, the NTNDP is not determinative. AEMO cannot direct a TNSP (except in Victoria) to undertake a given investment detailed in the plan. Instead, its role is to bring an alternative (long-term) focus and inform the market about potential development options, at best influencing investment outcomes (outside Victoria).

These arrangements are new. The first interim national statement (a precursor to the NTNDP) was published by AEMO at the end of 2009, and the first comprehensive NTNDP was published at the end of 2010. Consequently, the APRs published in mid-2011 were the first to set out the degree of difference or alignment with the NTNDP.

As the AEMC noted in its First Interim Report for its Transmission Frameworks Review (‘TFR’), differences in the formatting of reporting outcomes in the APRs

² NER clause 5.6.2.

³ While the AEMC has a ‘Last Resort Planning Power’ which it can exercise in the event that identified constraints do not appear to be addressed, this merely directs a TNSP to commence a RIT-T process, not to conduct any particular investment.

⁴ NER clause 5.6A.2 (b)(3).

between TSNPs have made it difficult to assess whether all issues in the NTNDP have been adequately considered by TNSPs (AEMC 2011f). In its Second Interim Report, the AEMC (2012j) noted that review participants had supported improved coordination of the APRs, and that it therefore expected this issue to progress without the need for formal requirements.

Is planning coordination effective?

The current planning arrangements described above have evolved over time, and represent an improvement in the degree of coordination between jurisdictions in the NEM. But have they gone far enough?

Previously, the Energy Reform Implementation Group (ERIG) identified that, due to reliability-driven planning at a jurisdictional level:

... investment decision making is biased toward investment within each state rather than, where it is efficient to do so, having a true national character. (2007, p. 12)

Not every sphere of regulation needs to be managed at a national level. Indeed, the principle of subsidiarity requires decisions to be taken by the lowest level of government capable of considering, and acting on, all the costs and benefits relevant to making the decision (PC 2012c). For example, planning and zoning requirements only affect parties within a limited area, and as such should be handled at local levels. However, where actions have an impact that extends beyond one jurisdiction, the efficient level of decision making tends towards increased coordination, or harmonisation, at a higher (that is, national or, where relevant, international) level. This allows the decision maker to properly consider all of the effects of a decision, rather than just those occurring in one affected jurisdiction.

In the context of electricity, the ‘network effects’ (chapters 15 and 17) present in the NEM suggest that, at the very least, strong coordination is necessary to properly account for inter-regional effects, and plan adequate levels of interconnection. Further, as interconnection increases over time, so too will the extent of the network effects, and thus the necessity for planning that adequately takes account of NEM-wide effects:

In an interconnected alternating current AC electricity grid, additions and subtractions of generation or network capacity at any point within the system affect conditions in other parts of the network. As a result, it is not possible to plan and develop subsections of the system in isolation. Efficient system wide development requires planning to be co-ordinated across generation, transmission and load. The increased level of interconnection in the NEM has elevated the need for NEM wide coordination for the efficient development of the entire transmission system and energy market. (ERIG 2007, p. 168)

The arrangements described above were implemented after the ERIG report. Grid Australia contends that the reforms have addressed the concerns raised by ERIG, achieved an optimal level of coordination and that the current approach ‘captures the strategic national perspective of AEMO with the detailed on-the-ground knowledge of the regional TNSPs’ (sub. 22, p. 17). But AEMO disagreed, and submitted that:

There are many examples of the state-by-state approach to transmission planning which inhibits the development of a national grid. ... Redundancy [reliability] driven investments ... are traditionally treated by the local network planner as a problem that must be solved solely from within the state. (sub. 32, p. 31)

Based on the relative consequences of inaction under the existing arrangements,⁵ TNSPs have more of an incentive to invest for reliability in their own jurisdiction than to address inter-regional issues. More practically, historical considerations and organisational culture could mean that TNSPs’ focus tends towards solutions in their own jurisdictions, where they are familiar with requirements (such as planning and zoning and environmental approvals), have greater experience with the range of other parties (such as construction firms) involved, and where the decisions of other TNSPs have less effect on outcomes (and their timing).⁶

In examining the issue of planning as part of the TFR, the AEMC acknowledged this issue although it noted that the extent of the problem is unclear and that there is ‘no indication of a lack of inter-regional capacity’. Nevertheless it concluded that there is:

... scope to increase the national coordination of planning. While it is not clear that the current framework is delivering manifestly inefficient outcomes, there are some gaps. For example, a TNSP may not give full consideration to investment in other regions that could more efficiently meet reliability standards in its own region(“cross-regional” investment). (AEMC 2012j, p. 59)

The AEMC went on to recommend increased coordination in planning, largely based on the current South Australian model (chapter 15).

There are several other policies that could potentially help to address the coordination issue. For example, introducing some form of inter-regional

⁵ As noted above, failure to comply with requirements to ‘take into account’, or set out the differences from the NTNDP can lead to an injunction, or a financial penalty. Conversely, failure to comply with reliability standards includes a range of penalties, up to loss of the business’ licence (chapter 15). Further, the physical consequences of not meeting reliability standards (in the ‘home’ jurisdiction) are also substantial.

⁶ For example, if a TNSP in jurisdiction A is responsible for an upgrade to improve reliability in jurisdiction B, the effectiveness (or otherwise) of this upgrade could affect incentive payments for the TNSP in jurisdiction B (chapter 15).

transmission charging, a matter currently being considered by the AEMC (2011b). The AEMC's 'optional firm access' package (chapter 18) could also assist, as where generators (or in the case of interconnectors, retailers) requested and paid for firm access paths that had inter-regional aspects, TNSPs would be obliged to invest accordingly.

For several reasons, including the need to better account for network effects, the Commission has recommended that AEMO become the national transmission planner (chapter 15). This has particular implications for the degree of interconnection in the NEM. A national planner would be able to consider the need for network investment on a NEM-wide basis. This would mean that a given transmission investment was judged solely on its (net) effect on the NEM as a whole, not on the jurisdiction in which the investment would be physically located.⁷ Under this national planning approach, interconnectors would cease to be a special case, and would be treated as 'just another' transmission line.

The Commission considers that the current interaction between TNSPs and AEMO is a valuable feature of the planning process, and should continue. However, under the Commission's proposed approach, the relationship would be inverted, with AEMO holding decision making power in regard to the specification of what should be built, when and where, with the TNSPs performing the role of informing, advising and publicly challenging the national planner through the APR and NTNDP processes. This interaction would function as a transparent check on AEMO's performance of its planning role (as noted below, a similar role is envisaged in the context of the RIT-T).⁸

As noted in chapter 15, if the Commission's recommendation for national planning were not to be accepted, an adapted form of the South Australian hybrid model (as recommended by the AEMC) is a second best alternative. It would increase coordination between jurisdictions relative to the status quo, but would not fully vest decision making power in a NEM-wide body. As explained in chapter 15, the Commission believes that this approach, whilst better than the status quo, at least as currently specified, has some disadvantages.

⁷ Note that the Commission's proposal envisages that while planning would be done on a NEM-wide basis, local conditions and preferences would still be taken into account. If probabilistic planning were used, local consumer preferences should be reflected in disaggregated measures of the value of customer reliability (chapter 14).

⁸ The operation of the AEMC's 'optional firm access' package would also provide another form of check on the national planner, as generators would be able to request (and pay for) levels of firm access that TNSPs would be obliged to build. To the extent that generators chose to take up firm access, some specific lines would be market-driven, and taken out of a planning context (chapter 18).

19.3 The Regulatory Investment Test for Transmission

The RIT-T is a cost benefit process that is done before all major new transmission projects, including interconnectors, are undertaken.⁹ It is not required if a transmission asset is being replaced, rather than augmented.

In attempting to replicate investment outcomes that would arise in a competitive market environment, the RIT-T aims to quantify the costs and benefits that accrue to those who consume, transport or generate electricity as the result of a new project; and to ensure that only projects with the highest net present value proceed. In doing so, it includes several categories of costs and benefits (box 19.1).

The RIT-T gives equal consideration to the interests of those who consume, produce and transport electricity. In effect, this is an efficiency test, and will give no weight to any redistributive outcome of an investment. To a large degree, decisions made under this rule will align with the overarching National Electricity Objective (NEO) as they will generally direct investment in the *long term* interests of consumers. (As noted in chapter 3, the NEO can also be seen as fundamentally an efficiency objective.)

The primary goal of the RIT-T is to identify both the most efficient transmission projects, and any more efficient (non-network) options, such as demand management, where they exist. However, the RIT-T is part of a broader regulatory process in which the building block process, incentive regulation and the longer term planning processes all play a role in promoting efficient investment decisions.

It is therefore important to consider the design of the RIT-T as part of the overall regulatory process. If other parts of the regulatory system are working well and providing appropriate incentives to provide a reliable, low cost network, the RIT-T would be less important. But if the regulatory system is providing weak incentives, the RIT-T will play a more important role in directing efficient investment.

Where reliability standards are set deterministically, a profit motivated TNSP has incentives to achieve these standards at least cost (regardless of whether a RIT-T is undertaken or not). At best, the reassuringly named ‘regulatory investment test’ may substantiate that the TNSP has achieved the least cost solution given the deterministic constraints, but it cannot alter the inefficiency of those constraints.

⁹ A major project is one where any of the options considered would cost more than \$5 million.

Box 19.1 **The costs and benefits in a RIT-T**

The RIT-T process is relatively simple, at least in principle. For any proposed new investment, the party performing the test compiles a list of options. These options can be network options, or they could be alternatives such as demand management or a new generator. At this stage of the process, interested parties are allowed to raise alternatives that must be considered or a rationale given for their exclusion.¹⁰

Once a list of options is finalised, the expected benefit of each project is calculated using the costs and benefit categories described in the RIT-T documentation.

The costs that can be included are:

- the costs of construction or providing the options
- operating and maintenance costs
- cost of complying with laws and regulations
- any other reasonable costs that are agreed to by the AER.

The benefits considered under the RIT-T include:

- decreased fuel dispatch
- reductions in voluntary load curtailment (when electricity users will reduce consumption for a price)
- reductions in involuntary load shedding (when electricity supply is cut off to parts of the network to maintain system security)
- changes in cost to other parties, such as the deferral of a new plant
- differences in the timing of other transmission projects
- changes in network losses or in ancillary services costs
- competition benefits
- option value (the benefit from retaining flexibility by taking a sunk action, such as reserving property rights, whose value could change in the future)
- adjustments for helping to meet the Renewable Energy Target

These costs and benefits are calculated in a number of forecast scenarios, and assigned a weight for the probability that each state will occur. The project with the highest, probability weighted, net present value is chosen by the TNSP for development.¹¹ Throughout the application of the RIT-T, the regulator only plays a role in monitoring issues of process, such as not following the consultation guidelines, and plays no active role in approving the RIT-T outcomes. Indeed, despite the name, this is not a test is involved in 'marking'. In reality, it is 'due diligence' by the TNSP, undertaken prior to an investment and carried out with some public involvement and transparency.

Source: AER (2010e)

Aside from the main goal of identifying the most efficient new investments, the RIT-T also performs several secondary, but still valuable roles. These include a (mandatory) consultation process to allow parties with relevant information for a particular investment to come forward. For example, if a generator announced that it was planning to commission a new plant in an area, it could make a network augmentation unnecessary.

The RIT-T also provides a platform for public debate around a particular transmission investment and provides transparency around the calculations used in coming to investment decisions. Importantly, the RIT-T does not involve the regulator approving (or vetoing) particular investment options.

It is important to recognise that the RIT-T is just the most recent form of regulatory test applied to transmission (box 19.2). Moreover, the test is a cost benefit analysis, and like all calculations of its type it will require assumptions, simplifications and in some cases, decisions about whether to include entire classes of benefits. Analysis is costly, and the goal of the RIT-T is to find the best project, not to produce the perfect estimate of the net benefit of any particular option.

Even so, it has been suggested that elements of the current RIT-T design are biased away from interconnector investment and that changes are required.

Box 19.2 **A brief history of regulatory tests**

The RIT-T is a relatively new process, and has only applied to transmission assessments initiated since 1 August 2010. A full RIT-T process is yet to be completed. Prima facie, its recent introduction might militate against reforms to the test at this juncture.

However, the RIT-T is in fact the result of an evolving process for the assessment of new transmission projects that began with the consumer benefits test included in the National Electricity Code prior to 1999 (AER 2009f, p. 3). As the name suggests, this test was based on whether the project represented a net gain for consumers of electricity.

As it transpired, application of this test proved to be problematic, especially if a project offered the prospect of a gain for consumers but imposed more than offsetting costs on other parties. After the rejection of a proposed South Australia – NSW interconnector, the National energy Market Management Company Limited ('NEMMCO') found that the customer benefits test was 'highly volatile' (ACCC 1999).¹⁰

The first regulatory test was introduced in 1999 by the ACCC and required the test to examine a net market benefit as the RIT-T does now. Versions 2 (AER 2004) and 3 (AER 2007b) expanded on the cost benefit framework and clarified some areas of uncertainty in its implementation.

The main changes to the process introduced with the RIT-T in 2010 were the requirement to do a cost-benefit test for projects performed for reliability reasons, rather than providing them at lowest cost, and the introduction of new consultation requirements. The RIT-T also provides more prescription in how to calculate costs and benefits (AER 2010f, p. 2).

The RIT-T framework

Who should perform the RIT-T

Despite its name, the RIT-T is not performed by a regulator. Instead, it is undertaken by the entity with responsibility for transmission planning in each jurisdiction.

Consequently, in NSW, South Australia, Tasmania and Queensland, the relevant transmission companies perform the test, with the limited oversight provided by the

¹⁰ Hypothetically a (short-term) customer benefits test could approve an investment that resulted in a benefit, of say \$1 million to electricity consumers, but incurred a cost on particular generators (who would be unlikely to be able to fully recover the cost through the wholesale market) of \$2 million. This could provide a disincentive for those generators to invest, and cause power supplies to fall below efficient levels in the future. (Note that the NEO, in focussing on the *long term* interests of consumers, would be unlikely to be met for such an investment.)

AER focused only on matters of process, rather than scrutinising the TNSPs' analysis. The TNSP is also responsible for arranging the construction of a new asset if the RIT-T finds it to be efficient to do so, and receives revenue based on both past and planned future investments through the regulatory determination process (section 19.1). There is no independent approval of the RIT-T.¹¹

In Victoria, the RIT-T is performed by AEMO as part of its planning function and the favoured option is constructed and ultimately owned by either the incumbent TNSP or a different party. For small projects, or projects that are unable to be separated from the network, these projects are provided by SP Ausnet for a negotiated fee. For larger projects that can be separated from the network, a tendering process is employed, and the incumbent TNSP as well as others can bid for the right to construct and own the augmentation. While the structure of the RIT-T itself is no different in Victoria, having an independent party responsible for performing it changes the nature of the test.

In chapter 15, the Commission recommends that the AEMO become the NEM-wide planner, responsible for the identification of all transmission augmentations. In line with the situation in Victoria, this change would see responsibility for performing the RIT-T shift from TNSPs to AEMO.¹²

There would be a number of advantages in having AEMO as an independent party perform all RIT-Ts, albeit in close cooperation with the TNSP whose local knowledge would be very important in testing the realism of assumptions used in the analysis. Cost benefit analysis of any complex future action is never an exact science. In estimating the costs and benefits of a new project it is necessary to make a number of assumptions, and, while some of these are specified in the RIT-T framework, others are necessarily left to the discretion of the party performing the test. Some important assumptions that affect the viability of future projects include:

- demand forecasts
- cost estimates of future projects
- the weighting and detailed application of future scenarios¹³
- estimates of when a new project may be viable

¹¹ In effect, the RIT-T is a test where the TNSP sets the questions, prepares the answers and marks the exams themselves. The AER and other parties act only as observers, able to comment but not 'mark' the exam themselves.

¹² Note that the Commission's recommendation on transmission planning differs from the AEMC's. The reasons for this difference are detailed in chapter 15.

¹³ At broad level, AEMO already effectively sets the scenarios as the TNSPs adopt those set out in AEMO's National Transmission Network Development Plan.

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- the extent to which other projects (including generation assets) will be delayed if a particular option is chosen
 - the value of improved reliability to customers
 - the costs and benefits of alternative options (including those posed by third parties).

Under the current framework, TNSPs undertaking the analysis can have a financial incentive to favour a particular outcome. In certain circumstances, a firm may wish, for commercial reasons, to delay or bring forward expenditure. It may also wish to select network options over non-network options, or favour an intrastate option to an interstate option. Such incentives may, consciously or unconsciously, reduce the impartiality of consideration of all options and thus diminished the capacity of the RIT-T to effectively perform its intended role.

On the other hand, it is worth noting that consultation on this topic has suggested that this type of commercial influence on RIT-Ts may be muted in practice as RIT-Ts are often performed in a separate part of the organisation, and can be outsourced to external parties. In these circumstances, it is conceivable that the detailed application of the test could occur in more of an arms-length fashion than might appear to be the case.

However, it seems unlikely that outsourcing or ring fencing of the conduct of the RIT-T will completely remove the scope for the financial incentives of a TNSP to influence outcomes. And whatever the ‘incentive impacts’ in particular circumstances, shifting responsibility for the conduct of the test to the AEMO (with the TNSP being able to actively participate during the process) would, in the Commission’s view, improve the general perception of the neutrality and objectivity of the test. Ensuring that this process is completely transparent would also serve to enhance the disciplines on AEMO to undertake its planning functions effectively.

Under the independent planner model proposed by the Commission, TNSPs would still play a major role in the RIT-T process and would work closely with the AEMO by providing information, contesting assumptions and putting forward alternative projects. This would result in an active engagement between the TNSP and AEMO, but in an environment where the AEMO could bring an independent and broader perspective to bear, in contrast to its current advisory, and relatively passive, role.

The \$5 million threshold

The RIT-T currently only applies to network augmentations where the cost of any option considered is over \$5 million.¹⁴ This excludes smaller projects as well as the replacement of existing assets. The \$5 million threshold for the RIT-T appears to be a low value, particularly as it applies to any option that could be contemplated. However, a low threshold helps minimise the risk of a company dividing a larger project into several smaller projects to avoid having to conduct a RIT-T.

The low threshold could be seen as imposing a significant compliance burden on relatively low-value projects. This would be the case if the costs of all the analysis required for a RIT-T could be attributed to the test process. But, in fact, much of the analysis that is required for a RIT-T would be done by a prudent business in any case, to ensure that the capital proposal was justified, even if the results were not published. Further, given that RIT-Ts are usually done well in advance of a project (as they are supposed to examine investments from the early options stage), it is unlikely that the process would delay the construction of a new asset.

Such considerations suggest that the current threshold is not unreasonable. However, under the Rules, the threshold is to be reviewed periodically by the AER. The first review is currently underway. The draft determination, issued in September 2012, concluded that the \$5 million threshold should be maintained, but that the consultation threshold of \$35 million be increased to \$38 million (AER 2012j). At this stage, the Commission agrees that a relatively low threshold seems appropriate.

Performing the RIT-T for replacements

The RIT-T is currently only applied for new projects. As such, when an existing asset needs to be replaced, it can be done without performing a cost-benefit test. This would be appropriate, if in most cases, the best investment option would be to replace the existing asset.

However, over time, many of the factors that influenced the original investment decision may have changed, and technological developments may offer alternatives. While TNSPs will have incentives to look at the relative efficiency of alternative options before deciding to replicate an existing asset, if they choose the replication option, any such assessment will remain internal to the provider and therefore not open to public scrutiny (outside of a overall, forward looking estimate included in

¹⁴ Further, where the preferred option does not cost more than \$35 million, the planner applying the RIT-T can be exempted from parts of the consultation process (AER 2012j, p. 6).

the revenue determination process). Indeed, there is the possibility that the exemption from having to conduct a RIT-T for replacement projects may have the perverse effect of motivating a TNSP to choose a simple replacement rather than another alternative, simply to avoid having to go through the RIT-T process.

Improving the transparency of the RIT-T

One of the main functions of the RIT-T is to provide a degree of transparency to the transmission investment process. It is therefore important that the RIT-T is itself a transparent process.

The second interim report of the Transmission Frameworks Review (AEMC 2012j) includes a number of suggestions for improving the transparency of the RIT-T process, including public reporting of the parties that stand to ‘win’ and ‘lose’ from a new project (even though such transfers are netted out during the calculation of the overall net present value). The review found that these changes ‘were almost universally supported’ (p. 6). However, as the AEMC noted (p. 74), increases in transparency should only be pursued up to the point at which the additional benefits are equal to the additional compliance costs entailed.

The Commission definitely agrees with this principle. However, as noted before, absent the public consultation, most aspects of the RIT-T process would be conducted by a prudent business before making a major investment, regardless of regulatory requirements. Making such analysis transparent, unless it would substantially risk damage due to disclosing confidential material, would involve little additional compliance cost.¹⁵ Indeed, as Hogan (2011, p. 25) noted in the context of cost allocation of transmission projects, the information that must be produced as part of the evaluation of investments can provide a basis for identifying project beneficiaries in a cost-benefit analysis.

Where possible, and as appropriate, such information could therefore be used to augment or inform existing modelling work. Moreover, while wealth transfers might not have an effect on short-term efficiency, in some cases they can have implications for long-term efficiency (chapter 17). In particular, where a wealth transfer is expected and repeated, it takes on characteristics of a long-term investment incentive.

¹⁵ Examples of confidential material include the details of contracts with construction firms. These firms could suffer financial loss if their competitors discovered, and copied, particular aspects of their bidding and contracting arrangements.

The future role of the RIT-T?

As discussed above, currently the RIT-T plays a limited role in the process of encouraging, determining and funding efficient transmission investment. It sits parallel to the regulatory determination process (and does not determine funding), the only involvement of the regulator is an assessment of procedural compliance (not approval of investments), and it only applies to certain transmission augmentations (not to replacements).

Of course, the current role of the RIT-T has evolved over time with the application, and review, of previous regulatory tests. As such, there may be sound (and efficient) reasons for what may appear to be, *prima facie*, deficiencies in the role of the RIT-T in the broader regulatory process.

In this light, the Commission is seeking comment on potential changes to the RIT-T. Participants should consider how these options would work in the current regulatory system, and also in the context of recommended future changes to transmission planning (chapter 15).

The Commission seeks participants' opinions as to whether the:

- *Regulatory Investment Test for Transmission should be applied to the replacement of existing assets*
- *Australian Energy Regulator could have an expanded role in the assessment of the Regulatory Investment Test for Transmission*
- *Regulatory Investment Test for Transmission could be used more formally in the Australian Energy Regulator's determinations.*

Calculating the benefits

Should the RIT-T include effects in other markets?

The RIT-T only allows benefits and costs to be counted where they apply to those who consume, produce or transport electricity. Some have suggested that allowing the impacts of an investment to be considered more generally may improve the RIT-T process.¹⁶ For instance, Grid Australia contended:

... major transmission upgrades may bestow wider economic benefits, which would not be 'counted' in a RIT-T assessment. ... However, any mechanism for capturing wider

¹⁶ This issue was also considered by ACIL Tasman (2006).

benefits should not unduly complicate what is a relatively complex (but feasible) assessment process. (sub. 22, p. 14)

Similarly, in the 2011 National Transmission Network Development Plan, AEMO argued that:

Changes to the national regulatory and transmission frameworks are needed to enable wider economic benefits beyond the electricity market to be considered, to maximise the value of these investments to Australia. (2011d, p.xxi)

However, as elaborated on in appendix D, the Commission considers that there are both conceptual and pragmatic reasons for not moving in this direction.

On conceptual grounds, including such effects would allow the transmission industry to count benefits that are not accessible for other industries (and nor would they be included in consideration in such industries). This might bias investment away from other sectors of the economy towards transmission projects. It would also require modellers to make difficult judgements about the relevance of potential market distortions in secondary markets to a particular investment project. TNSPs are not well-suited for such a role. Indeed, the Commission considers that the role of the RIT-T should be to try to produce investment decisions that (overall) mimic the investment outcomes that might eventuate in a competitive market. Accordingly, the focus should be on an assessment of the electricity market, not the entire economy.

On pragmatic grounds, calculating economy wide impacts would require the existing detailed market modelling of the electricity sector to be incorporated into either an extended partial equilibrium model or a general equilibrium model. This would be costly to achieve and would make the RIT-T process significantly less transparent (AER, sub. 13).

In any event, adding the complexity of economy-wide modelling is unlikely to dramatically change the outcome of RIT-T processes as most projects would have indirect costs as well as benefits (including the opportunity cost of investment in other industries).

DRAFT RECOMMENDATION 19.1

The Regulatory Investment Test for Transmission should not be amended to include indirect effects of investment decisions.

Allowing projects to be justified by reliability standards

The RIT-T aims to calculate the net present value (NPV) of identified options. However, currently, if the ‘identified need’ (or ‘driver’) for a project is to meet a reliability standard, the project with the highest NPV will be approved, even if that value is negative. As interconnectors do not have reliability standards, and must be justified on market benefit grounds (that is, they must have a positive NPV), this may mean that intra-regional projects are given priority over interconnectors.

One option for reform would be to assign reliability standards to interconnectors so that all interconnectors and intra-regional transmission are treated equally under the RIT-T. The AEMC considered this as a stand-alone option in its first interim report of Transmission Frameworks Review (AEMC 2011f). But the optional firm access (OFA) package, considered in the AEMC’s second interim report, included scope for parties to buy ‘firm’ rights for access to transmission capacity on interconnectors (chapter 18), replacing the need for interconnectors’ reliability standards as a stand-alone option.¹⁷

In chapter 15, the Commission is recommending moving to a probabilistic planning framework for all transmission projects. In the context of the RIT-T process, a move to probabilistic planning would mean removing reliability as a separately identified need, and in doing so remove any potential bias between types of projects. Benefits from improved reliability would instead be considered as a component of the overall benefits (in turn requiring measurement of the value of customer reliability (chapter 14)).

However, including reliability benefits is not straightforward if current approaches to reliability are retained:

- if transmission planning is driven by the specification of deterministic reliability standards (as is currently the case in NSW, Queensland and Tasmania), many transmission projects driven by reliability concerns (particularly intra-regional projects) would run the risk of failing a cost-benefit test. This would result in TNSPs having to conduct modelling and report on projects that show a net cost, but proceeding with (the best of) those projects to meet reliability specifications — in many respects, this is the current practice.
- in the case of the ‘hybrid’ planning currently used in South Australia (and proposed for NEM-wide application by the AEMC), while projects should in theory pass a cost-benefit test (chapter 15), there may be marginal projects, or

¹⁷ Under the OFA package, TNSPs would be obliged to maintain interconnector capacity to meet the subscribed levels of access. This level of capacity would be subject to a ‘firm access standard’ (chapter 18) which would effectively perform the same role as a reliability standard.

changes which have occurred since the hybrid standard was set, which result in the deterministically expressed standard not being entirely in alignment with economic benefit.

Accordingly, removing reliability as a separately identified need in the RIT-T requires at least a move to hybrid planning, but would only function smoothly in the context of probabilistic planning.

DRAFT RECOMMENDATION 19.2

In combination with the adoption of probabilistic reliability planning (draft recommendation 15.3), the Regulatory Investment Test for Transmission should be changed so that reliability is only assessed as a component of overall benefits and not as a separate criterion.

Competition benefits

The RIT-T can include consideration of ‘competition benefits’ — that is, the dilution of localised generator market power where a transmission expansion allows the wholesale market to access more competitive generation from elsewhere in the NEM.

The Grid Australia RIT-T Handbook (2011) divides the class of competition benefits into three categories:

- A reduction of deadweight loss resulting from generators being motivated to bid closer to their marginal cost. The size of this gain will be positively correlated to the elasticity of demand in the electricity market concerned.¹⁸
- An improvement in the merit order dispatch. With little to no competition, a generator may withhold some supply, which will result in lower merit (and higher cost) generators being dispatched, such as peaking plants, and a higher regional pool price. The introduction of further competition makes additional sources of power available to meet demand, reducing reliance on peaking generators and putting downward pressure on prices.
- A generator exercising market power can raise the price of electricity in an area and provide signals for new entrants. A transmission line may defer the entry of the new plant, which could be a significant cost saving that can be considered in the RIT-T.

¹⁸ There will be a rent transfer, from generators to consumers but, as discussed above, these are not considered under the RIT-T framework.

The Commission agrees with the framework provided in the Handbook, although it is unclear whether all of the information required for these types of calculation would ever be available in practice. The Commission also understands that, to date, the estimation of competition benefits has focused on benefits of lower fuel costs to energy users. This would suggest that competition benefits may be underestimated.

If, over time, any tendency to underestimate competition benefits is considered to be significant, an adjustment to the RIT-T methodology could be warranted.

Future scenarios

The Garnaut review (2008) raised concerns about the ability of the existing interconnector regulation to facilitate structural change (as carbon policies lead to changes in generator location and technology mix). In particular, Garnaut argued that transmission planners: ¹⁹

... must consider the effects of climate change on demand (higher temperatures) and supply (severe weather events, water scarcity and bushfires). (2008, p. 450).

The Commission agrees that modelling methodologies should aim to represent the variables that have major effects on the decision in question. However, these cannot always be accurately predicted, nor definitively incorporated into a model. Indeed, most modelling of potential futures will be, by its very nature, an estimate, involving simplified relationships between variables.

Currently, AEMO develops a range of future scenarios in the National Transmission Network Development Plan (AEMO 2011d). These scenarios incorporate a range of generation, demand and policy settings. The transparent process of scenario development also allows interested parties (such as network businesses, generators, users and academics) to test the validity of the scenarios on a regular basis. The scenarios are then used by TNSPs for their modelling in RIT-Ts, with each scenario given a probability weighting. The project that performs the best across the weighted scenarios is then selected.

Without requiring a focus on any particular future outcome (which would risk biasing investment decisions to cater for futures that might not eventuate), these scenarios will update to reflect changing policy settings and available information. Illustratively, AEMO's latest range of scenarios includes legislated carbon policies (as at January 2012), and also reflects the effect of such policies on economic

¹⁹ In his review, Garnaut (2008) contemplated a NEM-wide assessment, similar to the Californian Energy Transmission Initiative, as a role for the national transmission planner.

growth by adopting the Treasury's 'core' modelling forecast for the impact of the carbon price (AEMO 2012g).

The existing range of scenarios appear suitably broad, and are developed and updated independently of those who could have a financial incentive to game them. As such, the Commission considers that they are suitable for the task of planning for an uncertain future.

A bias away from gas transport alternatives?

Issues with the RIT-T process can occur when there is a choice between meeting a need with an electricity transmission project or through a gas pipeline. For example, electric power can either be generated at a gas field and transmitted to the city, or gas can be piped to the city and power generated there.

Under current NEM rules, provided that there is a transmission line nearby to the gas field, generators have an incentive to locate close to the gas fields, as they do not have to pay the full cost for the construction of the transmission line (only shallow access fees). Yet the capital cost of building infrastructure to transport gas is significantly lower than that for electricity, with some estimates suggesting electric energy is between one and a half and two and a half times as expensive to transport as the equivalent amount of gas energy (AEMO 2011d).

Further, a generator's choice of location can contribute to congestion in the transmission network, necessitating (or bringing forward) other transmission investments (currently a cost that is recovered from users, not generators). As such, locating close to a gas field may appear cheaper to generators, but it may have a higher long term cost to the economy as a whole (particularly to electricity users who ultimately pay for the transmission charges).

As it does not consider gas transport alternatives, the RIT-T could be seen as too narrow, and thus may not result in the most efficient method of transporting energy. However, TNSPs (and electricity planners more generally) do not have the authority to direct gas pipeline investment. Consequently, a RIT-T that considered gas and determined it was the best option, could lead to a perceived 'gap' in the market if pipeline owners chose not to invest (deploying their capital elsewhere). However, if the RIT-T analysis is transparent, and interested parties have a good understanding of the options (and benefits) considered, then normal commercial incentives may act to encourage an efficient outcome.

Given the problem arises due to generators not facing the 'true' cost of their connection to the electricity network, the solution lies not with the RIT-T, but in

exposing generators to a larger share of the network costs they create. Some potential options (such as ‘firm access’ payments which could create a level playing field for gas and electricity) are discussed in chapter 18.

20 Merchant interconnectors

Key points

- In the National Electricity Market (NEM), merchant interconnectors are distinguishable from regulated interconnectors in that their providers:
 - earn revenue by trading on the spot market by purchasing electricity in a lower priced region and selling it to a higher priced region, or by selling the rights to revenue traded across the interconnector
 - are not required to meet the Regulatory Investment Test for Transmission.
- At the commencement of the NEM, it was expected that merchant interconnectors would play an important role. This expectation has not been realised.
 - There is only one merchant interconnector — Basslink (between Tasmania and Victoria). However, it is arguably not a genuine merchant interconnector given its commercial relationship with the generator, Hydro Tasmania.
 - Two previous merchant interconnectors, Murraylink (between South Australia and Victoria) and Directlink (now called Terranora) (between New South Wales and Queensland) converted to regulated status soon after commencing operations.
 - There are no new merchant interconnector proposals.
- It is unlikely that the current limited role of merchant interconnectors will expand.
 - Regional price differences are too small to sustain the large investments involved, or to attract new entry. Furthermore, the added capacity of any new merchant (or regulated) interconnector would further diminish inter-regional price differences and, thus, revenues.
 - The application of the regulatory test to regulated interconnector proposals in the early years of the NEM may have had lasting impacts on the confidence of merchant investors.
 - International experience suggests that the success of the merchant model depends on transmission rights and nodal pricing, which would require fundamental design changes in the NEM.
- There appear to be no large regulatory biases against merchant interconnectors within the NEM. However, compared with generators, there are two minor issues.
 - Providers of merchant interconnectors cannot receive revenue from the Australian Energy Market Operator for frequency control ancillary services.
 - There is a lack of clarity around the minimum floor price that applies to merchant interconnectors.
- Another approach to interconnector investment is for generators, loads and other parties to propose and finance projects from which they benefit. Because of free-rider and coordination problems, this beneficiary pays approach is likely to be limited to investments with few and identifiable beneficiaries (for example, Basslink).
- Both merchant and beneficiary pays approaches to interconnector investment should be capable of being accommodated within a national planner model for transmission.

Previous chapters (chapters 17–19) have focused on various aspects about regulated interconnectors in the National Electricity Market (NEM).

An alternative to regulated interconnectors in the NEM is unregulated or merchant interconnectors. These are provided by ‘market network service providers’ (MNSPs) and are distinguishable in that they:

- earn their revenue by trading on the wholesale spot market by purchasing electricity in a lower priced region and selling it to a higher priced region, or by selling the rights to the revenue earned across their interconnector
- are not required to meet the regulatory investment test for transmission (RIT-T).

This chapter explores:

- the current role of merchant interconnectors in the NEM and whether that is likely to expand
- whether there are regulatory biases within the NEM against merchant interconnectors
- the scope for a beneficiary pays approach to interconnector investment.

20.1 The role of merchant interconnectors in the National Electricity Market

Within the NEM, there is only one merchant interconnector — Basslink which connects Victoria and Tasmania and which began operations in 2006 (box 20.1). Basslink assigned its rights to inter-regional revenues to the Tasmanian generator, Hydro Tasmania, for 25 years under the Basslink Services Agreement. Two other merchant interconnectors — Directlink (now called Terranora) and Murraylink — began operations in 2000 and 2002, respectively, and subsequently converted to become regulated interconnectors.

Like regulated interconnectors, merchant interconnectors can enhance competition within the NEM. In particular, they can:

- act as a competitor to regulated interconnectors as well as to generators in the linked regions
- facilitate interstate trade in electricity
- fill investment niches that have been overlooked by providers of regulated interconnectors (‘transmission network service providers’ or TNSPs).

Box 20.1 **Merchant interconnectors in the National Electricity Market**

Basslink (connecting Tasmania and Victoria) is currently the only merchant interconnector operating in the NEM. It is a high voltage direct current (DC) submarine cable link of 370 km length, connecting the Loy Yang Power Station in Victoria and the George Town substation in northern Tasmania. It has a capacity of 500 MW. Basslink was constructed by National Grid Australia between 2003 and 2005 in response to expressions of interest sought by the Tasmanian Government in the late 1990s. It began operations in 2006. Under the Basslink Services Agreement (which has a 25-year term), Basslink's entitlement to inter-regional revenues was assigned to the Tasmanian generator, Hydro Tasmania, in exchange for a facility fee and performance-related payments. Basslink is owned by CitySpring Infrastructure Trust, which is registered with the Monetary Authority of Singapore.

Two other merchant interconnectors previously operated in the NEM, but subsequently converted to become regulated network services.

Directlink (Terranora) (connecting New South Wales and Queensland) is a high voltage DC line of 180 MW capacity that extends 59 km between Mullumbimby and Bungalora in New South Wales, with two AC/DC (alternating current/direct current) converter stations and a single 110kV AC underground transmission link of about 4 km running from Bungalora to Terranora in northern New South Wales, where it interconnects with the Queensland power grid. It was developed as a joint venture of NorthPower, TransEnergie Australia, and Fonds de solidarite FTQ starting in 1999 and began operations in 2000. It converted to a regulated network service in 2006.

Murraylink (connecting South Australia and Victoria) is a high voltage DC link of 220 MW capacity, which extends 180 km from Red Cliffs in Victoria to Berri in South Australia. It was constructed by Trans Energie Australia. It began operations in 2002. It converted to a regulated network service in 2003.

APA Group now operates both Directlink (Terranora) and Murraylink.

However, some participants had concerns about merchant investment in transmission (including in interconnectors) or considered that it currently had a very limited role in the NEM. Their arguments included the following:

- It is more efficient to rely on a coordinated approach to investment in transmission than on decentralised market-based approaches. For example, the Australian Energy Market Commission (AEMC) said that greater coordination of inter- and intra-regional planning was desirable:

Therefore, although interconnections between regions provided by regulated TNSPs might tend to 'crowd out' merchant investment, relying on a solely merchant approach is unlikely to be practical or efficient. (sub. 16, p. 8).

- There are limited commercial opportunities for viable merchant interconnectors. The significant regional price differentials that underpinned the initial three

merchant interconnectors have not been sustained between those regions and have not been evident between other regions. Indeed, inter-regional price differences are currently insufficient between all regions to generate enough revenue for a potential merchant interconnector to cover the costs associated with their capital investment. (This issue is considered in further detail later in this section.)

- Merchant interconnectors have an incentive to limit the amount of electricity they transport in order to keep regional price differentials high. For example, the Major Energy Users said:

The problem with Directlink, and other so-called ‘market network service providers’, in contrast to normal regulated interconnectors, is that they must seek to maintain a certain differential between regional pool prices in order to gain revenue to cover their annual costs — of the order of \$10/MWh based on typical costs of HVDC [high voltage direct current] systems of the size used in Directlink. In this respect, they have motivations more like those of generators to keep a high pool price in the receiving system. ... (sub. 11, p. 46)

This section discusses the economic basis for, and concerns about merchant interconnectors, the regulatory arrangements within the NEM that allow their operation and the scope for the role of merchant interconnectors in the NEM to expand.

The economic debate

The merchant model of transmission investment has been the subject of debate amongst economists since it was first described in the early 1990s.¹

Proponents of the merchant model (initially Hogan 1992 and, more recently, Littlechild 2004, 2011a) argue the following. In return for investment in additional transmission capacity, merchant investors receive property rights that allow them to collect congestion rents equal to the difference in nodal energy prices associated with the incremental point-to-point transmission capacity their investments create. The value of these rights to receive congestion rents is represented by the revenues merchant investors receive to cover the capital and operating costs of their investments and provides the financial incentives that guide ‘market-based’ transmission investment. Investment is then optimal. This challenges the previously

¹ The economic literature on merchant investment in transmission in chronological order includes: Hogan (1992); Littlechild (2004); Joskow and Tirole (2005); Brunekreeft (2004, 2005); Knopps and de Jong (2005); Rious (2006); Leautier and Thelen (2009); de Hauteclocque and Rious (2010); Kapf and Pelkmans (2010); Hogan et al. (2010); Littlechild (2011a); and van Koten (2012).

held assumption that transmission networks are ‘natural monopolies’ that must be regulated.

However, in their seminal paper, Joskow and Tirole (2005) argued that the conditions required for merchant investment in transmission to be optimal — namely that there is competition, free entry and decentralised property-rights based institutions, and market-based pricing for transmission — are not likely to be met in practice. Relevant considerations here include market power of generators, lumpiness of investment, and strategic behaviour and problems with coordination with other investors (or beneficiaries). These market failures mean that the level of capacity installed by merchant investors is likely to be inefficient. Although Joskow and Tirole admitted that the alternative model of the ‘regulated transco’ has various inefficiencies in practice, they considered it was unlikely that policy makers could rely primarily on the merchant model for an efficient level of transmission investment. In another paper, Joskow (2005b, p. 46) argued that merchant transmission might be a complement but not a substitute for regulated transmission, was likely to make only a very small contribution and efforts to debate its role had been a ‘distraction’.

Several other economists have similarly contended that the role of merchant transmission is likely to be limited. For example:

- Brunekreeft (2005) argued that merchant transmission would be more viable in the United States with nodal pricing and financial transmission rights, but in markets with regional or zonal pricing, merchant transmission would be limited to interconnectors between adjacent regions or zones.
- Rious (2006) argued that merchant transmission would be efficient where economies of scale in transmission were small relative to the size of the market, where DC transmission had a cost advantage over AC transmission, and where differential prices could be maintained.

Littlechild (2011a) attempted to address Joskow and Tirole’s arguments by applying a ‘comparative institutions’ approach to comparing merchant and regulated transmission. He sought to identify what have been the main market failures and regulatory failures, as predicted in theory and in practice in Australia and in Argentina (with its ‘beneficiary pays’ approach). He found that merchant transmission had not exhibited market failures and that regulated transmission exhibited regulatory failures. Lack of coordination (between transmission users and investors) had been a challenge with both approaches. He concluded that regulatory frameworks should be improved to remove barriers to merchant transmission and to facilitate coordination between transmission users and investors.

What is clear is that there is no consensus among economists on the role of merchant transmission investment in electricity markets. As Littlechild said:

There seems to be common ground on the likely need for more transmission investment and the possibility that some form of merchant investment could play a role somewhere. However, there is apparently little agreement among economists as to whether this could or should be a relatively small or large role, and what kinds of policies are best suited to delivering this. (2011a, pp. 2–3)

Safe harbour provisions

When the NEM commenced in November 1998, the then National Electricity Code Administrator (NECA) acknowledged that there would be difficulties in applying a market-based approach in relation to ‘electricity transport’, which was why the initial National Electricity Code (‘the Code’) focused on network services as ‘regulated’ services:

... it was recognised that serious technical impediments existed to moving to a competitive market in electricity transport. For example, the strong operational interdependencies that arise in a free-flowing AC meshed network make it difficult to apply a market based approach. Therefore, apart from a few exceptions, the Code treats network services as prescribed services ... to be provided by regulated monopoly businesses. (NECA 1998, p. 1).

However, the Code envisaged that merchant investors would have a role in relation to interconnectors, but that appropriate ‘safeguards’ would need to be developed by NECA:

The Code envisages that under some circumstances it may be feasible to adopt a competitive approach to inter-regional transport. Such a concept is potentially attractive in that it would avoid the regulatory problems and costs associated with centrally managed augmentation, however, there would need to be adequate safeguards to promote efficient and equitable outcomes. The Code is silent on what those safeguards would be, specifying that the market participation rules for non-regulated interconnectors will be established by NECA through the Code change process. (NECA 1998, p. 1)

These safeguards, described as ‘safe harbour provisions’ for the participation of merchant interconnectors in the NEM (box 20.2), were developed by NECA in 1999 and later reflected in the Code by amendments authorised by the Australian Competition and Consumer Commission (ACCC) in 2001.

Box 20.2 **Safe harbour provisions**

In July 1999, as part of its broader transmission and distribution pricing review, the NECA) developed an initial framework — described as ‘safe harbour provisions’ — to enable the market participation of non-regulated (entrepreneurial) interconnectors.

NECA subsequently applied to the ACCC in July and August 1999 to authorise proposed amendments to the Code (and to the NEM access code), which reflected the initial framework.

In its authorisation of the proposed amendments in September 2001, the ACCC set out the safe harbour provisions for merchant interconnectors — called ‘market network service providers’ (MNSPs) as follows:

- The interconnector must comprise a single two-terminal element of at least 30 MW capacity that directly connects networks in different price regions.
- The interconnector must be scheduled² and subject to analogous rights and obligations to those applicable to scheduled generators and loads.
- The MNSP is entitled to revenue from buying and selling energy in two regions and from providing ancillary services.
- Flow through the interconnector must be independently controllable if the interconnector forms part of any network loop.
- The MNSP must bear the full cost of dedicated connection assets plus other network charges and rebates necessary for efficient investment and utilisation signals.
- The MNSP must enter into a connection agreement with the interconnected network in each region.
- The MNSP must pay for services to support the operation of the interconnector as well as compensate for any adverse impact on other parts of the network.
- The powers of the then National Electricity Market Management Company (now AEMO) to direct the MNSP will be the same as its powers to direct other scheduled plant and the MNSP will be entitled to similar compensation.
- Some or all of the MNSP capacity may be used for a reserve trader contract.
- The MNSP can apply to convert to regulated status at any time.
- The MNSP must submit a code consistent access undertaking to the ACCC.

Although there have been regulatory changes since the ACCC’s authorisation of 2001, by and large, these safe harbour provisions continue to be reflected in the current National Electricity Rules.

Sources: ACCC (2001); NECA (1998; 1999).

² The terms ‘scheduled network service’ and ‘scheduled network service provider’ tend to be used within the context Rules governing the coordinated central dispatch process (of bids and offers) operated by AEMO. For example, clause 2.5.2 (4) of the Rules provides that ‘scheduled network service providers’ are required to submit ‘a schedule of dispatch offers’ for their ‘scheduled network services’.

Many of the safe harbour provisions continue to survive in the current National Electricity Rules (the ‘Rules’). For example:

- Clause 2.5.2 relating to the classification of a ‘market network service’ — which covers merchant interconnectors — includes the following provisions:
 - The market network service is to be provided by network elements that comprise a two terminal link and do not provide a regulated transmission and distribution service (for example, a service subject to a revenue determination by the Australian Energy Regulator (AER)).
 - The MNSP must be registered to operate in the NEM and, thus, must satisfy the prudential, technical and other requirements.
 - The connection points of the relevant two-terminal link are assigned to different regional reference nodes.
 - The relevant two-terminal link through which the market network service is provided, does not form part of a network loop or is an independently controllable two-terminal link, and has a registered power transfer capability of greater than 30 MW.³
 - The market network service may be converted by the AER into a regulated transmission or distribution service.
- Clause 3.8.6A (g) and (h) sets out the formulaic basis for how MNSPs earn revenue from trading on inter-regional price differences in the NEM (box 20.3).

Since the introduction of the safe harbour provisions in 2001, there have been two key developments concerning merchant interconnectors.

The first was the events surrounding the application of the then regulatory test to early proposals for a regulated interconnector between New South Wales and South Australia — the SANI proposal in 1997, which was amended to the SNI proposal in 1998. These included court action by the owners of Murraylink — concerned about the impacts of the SNI proposal on their merchant interconnector — that ended in an appeal to the Victorian Supreme Court. Murraylink converted to a regulated service during the court action and lost its appeal in the Victorian Supreme Court in July 2003. The SNI proposal did not eventuate.

³ The National Electricity Code Administrator argued that the complexity of reviewing and approving interconnector schemes of smaller than the 30 MW threshold may outweigh the benefits, and that the threshold is consistent with the provisions applying to generation (NECA 1999, p. 100). The Australian and Competition and Consumer Commission in its determination authorising the initial safe harbour amendments (2001) to the National Electricity Code appeared to accept this argument.

Box 20.3 **How do merchant interconnectors earn revenue?**

Clause 3.8.6A (g) of the National Electricity Rules sets out a formula for the net revenue that a market network service provider can expect to receive for energy delivered between regions A and B:

$$\text{Net revenue} = \text{PB} \times \text{FB} - \text{PA} \times \text{FA}$$

Where

PA and PB are the prices at the scheduled network service's connection points A and B, which are assumed not to change as a result of the incremental transfer.

FA and FB are the energy transfers scheduled by central dispatch for receipt by the scheduled network service at connection point A and delivery at connection point B respectively.

FA and FB are deemed to be related by the loss versus flow relationship published by AEMO.

Clause 3.8.6A (h) provides that the price at a connection point is related to the regional reference node price and loss factors:

The price at a connection point will be deemed to be related as follows to the price at the regional reference node to which that connection point is assigned.

$$P = \text{RP} \times \text{LF}$$

Where

P is the price at the connection point

RP is the price at the appropriate regional reference node.

LF, where the scheduled network service's connection point is a transmission network connection point, is the relevant intra-regional loss factor at that connection point, or where the scheduled network service's connection point is a distribution network connection point, is the product of the distribution loss factor at that connection multiplied by the relevant intra-regional loss factor at the transmission network connection point to which it is assigned.

To give an example, if the spot price in region A is \$25/MWh and in region B is \$35/MWh, the flow from region A to region B is 400 MW, and losses are zero, then the inter-regional residues that accrue and hence the revenue that a MNSP can earn is:

$$(\$35/\text{MWh} - \$25/\text{MWh}) \times 400 \text{ MW} = \$4000/\text{h}$$

Source: National Electricity Rules.

The second development was that, in a 2003 report to Council of Australian Governments on reform of energy markets, the Ministerial Council of Energy (MCE) signalled a policy shift in relation to merchant interconnectors:

The MCE believes that the current arrangements for the coexistence of regulated and market provision of transmission have not resulted in optimal outcomes, and supports removal of biases towards unregulated investment. The MCE will develop code changes and establish a level playing field between regulated and market transmission for implementation in July 2004. The code changes would recognise and protect the rights of existing investors in market transmission services. (MCE 2003a, p. 11)

These regulatory changes appeared to have been given effect in the National Electricity Rules in 2006 in relation to the determination of the opening regulatory asset base of former market network services⁴ (AEMC 2006b).

Is their scope for the role of merchant interconnectors to expand?

Despite the introduction of the safe harbour provisions, it is apparent that early expectations about the role of merchant interconnectors in the NEM have not been realised.

- As noted, there is currently only one merchant interconnector in the NEM — Basslink (between Tasmania and Victoria). Moreover, it is arguable whether Basslink is a genuine merchant interconnector as it is shielded from the commercial risks associated with earning inter-regional revenues by receiving a flat fee from Hydro Tasmania. To the owners of Basslink, it is akin to a regulated interconnector. Hydro Tasmania, as a generator, obtains a commercial benefit when it exports power by way of Basslink, over and above the normal merchant interconnector inter-regional revenues that would otherwise be available to it.
- The other two previous merchant interconnectors in the NEM — Murraylink and Directlink (Terranora) — converted to regulated transmission services within six years of commencing operations. Murraylink applied for conversion one week after commencing operations.
- There have been no new merchant interconnector proposals since Basslink began operations in 2006, and none is expected.

This is in contrast to the experiences of electricity markets in the European Union and in the United States, where the regulators have liberalised their regimes to allow merchant investors to operate (appendix E). A number of merchant transmission projects have developed in response to these actions.⁵

⁴ The regulatory changes applying to the determination of the opening regulatory asset base of former market network services would not apply to Basslink, were it to cease to exist as a ‘market network service’. Instead, Basslink is subject to grandfathered provisions under the Rules (clause 11.6.20), which applied at the time it entered into operations.

⁵ In the United States, merchant transmission projects have included the Cross-Sound Cable between Connecticut and Long Island, New York; Linden which involved adding a Variable Frequency Transformer to an existing line between Linden, New Jersey and Staten Island, New York; Chinook, Zephyr and Southern Cross, which are transmission lines connecting new renewable generation plants to existing transmission networks in certain US States; and TresAmigas in New Mexico a proposed super interconnector joining three asynchronous grids (Werntz 2011). In the European Union, merchant transmission projects have included: EstLink between Estonia and Finland; BritNed between Great Britain and the Netherlands; Imera/East-

In Australia, however, even with a more liberal regulatory regime, several factors suggest that the current role of merchant interconnectors in the NEM is unlikely to expand.

First, the three merchant interconnectors initially entered the NEM when inter-regional price differentials were over \$100/MWh (shaded price differentials in table 20.1). Differentials of this magnitude have not been evident since, and are currently between \$0.60/MWh and \$5.30/MWh, which is likely to have deterred entry of new merchant interconnectors. Indeed, the (Tasmanian) Electricity Supply Industry Expert Panel suggested that price differentials have not been large enough for the existing merchant interconnector to earn sufficient revenue from this source, to cover its costs.

The direct arbitrage revenue opportunities made available to Hydro Tasmania by Basslink have not, on their own, generated sufficient revenue to cover the overall cost of Basslink to Hydro Tasmania in any year since the link commenced commercial operation, although the business case was not predicated on them doing so. (2012a, p. 54)

The AEMC said:

To date, our work, and stakeholder views, on the [transmission frameworks] review have not suggested that attempting to promote a greater level of unregulated investment in interconnectors would be an appropriate course of action. In order for such merchant interconnectors to be economic, large price differences would be required between regions, and these would need to be maintained even after the interconnector was operational (as the interconnector would be remunerated through the difference in regional prices). (sub. 16, p. 8)

There are risks to the owners of a merchant interconnector that the extra capacity added by any new interconnector would further diminish inter-regional price differences and, thus, revenues.

Second, events surrounding the proposals for regulated interconnectors SANI/SNI between 1997 and 2003, including the resulting court action by Murraylink, may have had lasting adverse effects on the confidence of investors regarding the potential to make commercial returns from merchant interconnectors vis a vis regulated interconnectors.

West Cables between Great Britain and Ireland; and the Arnoldstein-Tarvisio interconnector between Austria and Italy (Cuomo and Glachant 2012).

Table 20.1 Regional differences in average annual (nominal) prices^a
\$/MWh

Year	NSW– Qld	NSW– SA	NSW– Snowy ^b	NSW– Vic	Vic– Snowy ^b	Vic– Tas ^c	Vic–SA
1998-99	18.52	122.89	0.79	3.20	3.99		119.69
1999-00	15.84	31.00	0.31	1.92	1.61		32.92
2000-01	3.64	18.7	0.63	6.88	7.51		11.82
2001-02	0.58	3.15	3.17	3.79	0.62		0.64
2002-03	4.88	2.80	3.08	5.35	2.27		2.55
2003-04	4.19	2.49	1.57	6.99	5.42		9.48
2004-05	10.37	3.26	5.28	11.71	6.43	162.76	8.45
2005-06	9.12	0.52	6.15	4.77	1.38	24.29	5.29
2006-07	6.58	7.11	3.53	3.92	0.39	5.24	3.19
2007-08	10.68	31.84	3.83	5.13	1.30	7.89	26.71
2008-09	4.85	12.13		2.97		16.66	9.16
2009-10	10.89	11.12		7.91		6.91	19.03
2010-11	5.77	4.16		9.65		2.36	5.49
2011-12	0.60	0.61		2.39		5.30	3.00

^a Prices are absolute differences in regional reference node prices. ^b The Snowy region was abolished in the NEM on 1 July 2008. So no inter-regional price data are available from 2007-08. ^c Tasmania joined the NEM on 29 May 2005. So no inter-regional price data are available before 2004-05.

Sources: Commission calculations based on AEMO (2012i).

Third, the success of the merchant model in other countries (and in theory) is contingent on the presence of transmission rights and nodal pricing, which would involve fundamental design changes in the NEM.

- A shift to nodal pricing from regional pricing in the NEM would create more arbitrage opportunities for merchant investors in transmission (not just interconnectors) to earn revenue. Nodal pricing is discussed briefly in chapter 18 on identifying future transmission.
- Allowing merchant investors to assign physical and financial transmission rights over an interconnector would improve their flexibility in financing and managing the risks of their investment. This is discussed further in the next section.

Although the role of merchant interconnectors seems unlikely to expand within the current NEM, this might change marginally under the Commission's proposals regarding NEM-wide transmission planning (chapter 15). Within this context, TNSPs could tender the building and operation of new interconnectors to merchant investors.

The focus of the remainder of this chapter is on existing regulatory biases against merchant interconnectors and on the scope for a beneficiary pays approach to interconnector investment.

20.2 Regulatory biases

Providers of merchant interconnectors compete with generators in supplying electricity.

In principle, there should be no regulatory biases in the NEM that favour one form of competition over another currently or in the future. Any biases could lead to inefficient outcomes in the supply of electricity in the NEM, with potential adverse effects on productivity and electricity prices. This principle applies not only to the current suppliers of electricity (and other services) in the NEM, but to future suppliers, including any new MNSPs.

Participants have not drawn the Commission's attention to any major regulatory biases in the NEM towards or against MNSPs, although there may be some less important ones. While these biases may not directly affect the only existing merchant interconnector, Basslink (because it is protected by its commercial relationship with Hydro Tasmania), it is possible that they could in the future collectively frustrate the entry of new MNSPs.

The impacts of new investment proposals by transmission network service providers

A major concern for a MNSP (and a generator) about a TNSP's proposed investment in an interconnector is the risk that its assets will become less valuable. The additional capacity arising from the TNSP's investment is likely to reduce inter-regional price differences and, thus, the ability of an existing MNSP to earn revenue as well as depreciate the commercial value of its interconnector before the end of its physical life.

As in competitive markets, such devaluation of existing assets could be an efficient outcome if a new investment proposal involves more productive interconnector technologies. Indeed, this could arise not just from a TNSP's proposed investment, but also by the entry of future more productive MNSPs or even new generators. Asset devaluation is one of a suite of commercial risks that MNSPs bear when participating in the NEM.

However, the risk of asset devaluation from the investment decisions of a regulated entity, which does not face the full commercial risks of its investments, could potentially be seen as a form of regulatory bias against existing and proposed new MNSPs.

Under the Rules, TNSPs must generally apply the RIT-T to proposed investments, with an estimated capital cost of more than \$5 million. The purpose of the RIT-T is to identify a credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market. The AER (2010h) has issued guidelines about the RIT-T. (Further details and a discussion about the RIT-T are in chapter 19.)

The wording of the Rules (and the AER Guidelines) in relation to the RIT-T is broad enough to ensure that the impacts of a TNSP's proposal on MNSPs or generators (along with any other party) are taken into account. For example, the Rules require that the TNSP:

- provides 'an assessment of reasonable scenarios of future supply and demand if each credible option were implemented compared with a situation where no option is implemented' (clause 5.6.5B(c)(1))
- quantifies 'any other class of costs that are determined to be relevant' by them and agreed to by the AER before a project specification consultation report is made available to other parties, or else specified as a class of cost (clause 5.6.5B(c)(8) (iv))
- prepares a 'project specification consultation report', which, among other things, describes all credible options of which the TNSP is aware that address the identified need. These credible options may include market network services (clause 5.6.6 (c) (5))
- publicly consults on the RIT-T.

Also, the Rules enable the AER to intervene where other parties dispute the RIT-T's conclusions.

The Commission further notes that its proposal for a NEM-wide planner approach to transmission expansions (draft recommendation 15.2), and with that a shift in responsibility for undertaking cost-benefit analysis of interconnector proposals away from TNSPs to AEMO, would allow a more consistent approach to taking account the impacts of TNSP investments on existing and proposed MNSPs and generators.

Frequency control ancillary services

Frequency control ancillary services (FCAS) are used by AEMO to maintain the frequency of the power system within a small band around 50 hertz to ensure system security and reliability (box 20.4). AEMO procures FCAS in eight separate (but not regional) markets from market participants, mainly generators. In the last

12 months, the payments made by AEMO for FCAS totalled around \$12 million (based on Commission calculations using AEMO 2012i).

Box 20.4 Frequency control ancillary services

AEMO is responsible for ensuring that the power system operates in a safe, secure and reliable manner (AEMO 2010, p. 1). It uses ancillary services to maintain key technical characteristics of the system, such as frequency, voltage and network loading.

Frequency control ancillary services (FCAS) are used by AEMO to maintain the frequency of the power system within a narrow band around 50 hertz. The frequency may change due to unpredictable shifts in the energy demand and supply balance. For example, if a generator trips, then there may be a sudden drop in frequency; or if demand is less than supply, then frequency may increase.

AEMO operates eight separate markets for the delivery of FCAS:

- regulation raise/lower (used for minor deviations outside a narrow frequency band of around 50 hertz)
- contingency fast raise/lower (to be activated within six seconds to halt a large sudden change in frequency)
- contingency slow raise/lower (to be activated in 60 seconds to stabilise the frequency after a large sudden change)
- contingency delayed raise/lower (to be activated within five minutes to restore the frequency to normal)

The process AEMO uses to match supply and demand in each of the FCAS markets is similar to that used to dispatch generators in the energy market. Participants can offer or bid to supply FCAS in any of the eight markets. An offer or bid for a raise service represents the amount of MWs that a participant can add to the system in the needed time frame to raise frequency. AEMO procures its required amounts of FCAS in each of the eight markets in merit order of price as determined by the NEM dispatch engine (NEMDE).

During periods of high or low energy demand, the NEMDE may move the energy target of a generator or load in order to minimise the total cost of energy and FCAS to the market. This process is called co-optimisation and is an inherent feature of the NEMDE.

Sources: AEMC (2012p); AEMO (2010a, 2012h).

There is no provision in the Rules for MNSPs to make bids related to FCAS and, thus, earn revenue for the FCAS they transfer. As Hydro Tasmania said:

... no charging arrangement is specified in the NER [National Electricity Rules] to compensate a MNSP for transporting FCAS. Basslink currently transports FCAS but receives no fee for this service. Further, Basslink's energy transport (and thus its actual market revenue) is reduced to ensure FCAS is carried. (sub. 41, p. 4)

In the development of the safe harbour provisions applying to MNSPs, both NECA and the ACCC (which had regulatory responsibility for the National Electricity Code at the time) envisaged that MNSPs could earn revenue from providing ancillary services (NECA 1999, vol. III; ACCC 2001, p. 126). However, when the Code changes were gazetted in December 2001, they contained no provision for MNSPs to make bids or receive revenue for transferring FCAS.

The AEMC considered this gap in the Rules in a rule change request by Hydro Tasmania in 2007 concerning the dispatch of scheduled network services. Although not central to its consideration of the rule change request, the AEMC expressed the view that there:

... appeared to be no clear reason for the lack of alignment between the FCAS and energy markets in terms of the ability of MNSPs to capture the value of the energy transfer but not that of the FCAS transfer. ... this lack of alignment might be addressed through amendments to the MNSP rules; however, ... this matter was outside the scope of [the] Rule change proposal. (2007b, p. 20)

There appears to be no obvious rationale for the different treatment of MNSPs and other market participants in FCAS markets. Although the revenues that MNSPs might earn from FCAS are unlikely to be large compared with the potential to earn inter-regional revenues from the transport of energy, denying MNSPs the opportunity to earn this revenue appears inappropriate. There is a theoretical case that this should be reviewed by the AEMC.

However, as Hydro Tasmania has noted (sub. 41, p. 4), the AEMC review would need to address complexities around the FCAS markets for what is likely to be a problem of ‘small materiality’. Therefore, the Commission considers that the AEMC review is not a priority, but might be undertaken as part of an omnibus review of lower priority Rule changes at a time deemed appropriate by the AEMC.

Negative bidding by market network service providers

The AEMC is currently considering a rule change request from International Power-GDF Suez Australia and Loy Yang Marketing Managing Company to set a floor price of zero for the offers of ‘scheduled network service providers’ (AEMC 2012p). The term ‘scheduled network service provider’ is defined in the Rules and is regarded by the AEMC as equivalent to a MNSP (2012p, p. 2).⁶ If the

⁶ The Rules classify ‘market network services’ as ‘scheduled network services’ (clause 2.5.3 (a)), which is probably why the AEMC treat scheduled network service providers and MNSPs as equivalent. See footnote 2 for an explanation of terms ‘scheduled network service’ and ‘scheduled network service provider’.

rule change request is accepted by the AEMC, it would mean that MNSPs would be treated differently from generators under the Rules.

The proponents are concerned about the impacts of the bidding behaviour of Hydro Tasmania and Basslink on Latrobe Valley generators. When there is a transmission constraint in the Latrobe Valley, generators have an incentive to offer their energy at the price floor of -\$1000/MWh in order to maximise their dispatch. If both Hydro Tasmania and Basslink (under direction from Hydro Tasmania) each bid at the price floors, the effective offer price of Hydro Tasmania's energy at the Loy Yang connection point would be -\$2000/MWh, ignoring losses. This offer price would effectively undercut the price floor — and the price offered by the Latrobe Valley generators — with the effect that Hydro Tasmania would be dispatched ahead of the Latrobe Valley generators, which would then lose revenue.

The proponents considered that the current bidding rules distorted the market as some generation is prioritised through an 'artefact of the market rules' (AEMC 2012p, p. 7). They stated that their proposed rule change would improve their contract market outcomes by ensuring that the most efficient generation would be dispatched and by providing greater certainty in dispatch for generators.

The AEMC has reported that it will release a draft determination on the rule change request in November 2013, with a final determination in January 2014.

The Commission notes that the rule change request being considered by the AEMC is in response to a specific problem — namely, disorderly bidding by generators in the presence of a transmission constraint in the Latrobe Valley, where one of the generators has a commercial relationship with the MNSP. Another option to address disorderly bidding is the introduction of optional firm access in the short term and, potentially, consideration of nodal pricing in the long term (discussed in chapter 18).

Adopting the rule change request to address disorderly bidding in the Latrobe Valley would have wider ramifications for any future MNSPs in the NEM. Setting aside the issue of whether future MNSPs would be commercially feasible, imposing a zero price floor on all MNSPs would treat them differently from generators under the Rules. Such differential treatment could impede any possible new entry by MNSPs and affect future competition in the NEM.

Concerns about the potential for Hydro Tasmania and Basslink to jointly exercise market power through combined negative bidding could possibly be addressed by

the ACCC under Part IV of the *Competition and Consumer Act 2010*.⁷ If the ACCC found it appropriate to do so, it could request an undertaking from both parties that their bids in combination do not fall below the price floor applying to independent generators and MNSPs of -\$1000/MWh. (Alternatively, the ACCC might potentially require that Hydro Tasmania is prevented from influencing the bidding behaviour of Basslink.)

The Commission notes that there is lack of clarity in the Rules as to what is the appropriate price floor for MNSPs. AEMO has administratively set this to be the same as that applying to generators under the Rules. Formalising this administrative action into a rule would create certainty for all market participants and would seem, in principle, to have merit. However, as with the inability of MNSPs to receive FCAS payments, such a rule change would not be a priority and might be undertaken as part of an omnibus review of lower priority Rule changes at a time deemed appropriate by the AEMC.

Transmission rights

The NEM is underpinned by open access for the use of the transmission (and distribution) network. This applies to regulated and merchant interconnectors. As the AEMC (2011f) noted in its first interim report on the transmission frameworks review:

Currently the NEM operates under an open access regime. Generators have a right to connect to the transmission network, but this right does not extend to a firm right of access across the network to the RRN [regional reference node]. Generators instead are granted access when two conditions are met: they are scheduled in the merit order and there is no relevant congestion on the network. Generators do not have an inherent right to be dispatched, nor do they have a right to be compensated when constrained-off. (p. 57)

Several academics (for example, Hogan 1992) have emphasised that the ability to assign transmission rights (both physical and financial) is necessary for the commercial viability of merchant transmission. In particular, transmission rights enable merchant investors to raise finance and diversify their risks of investment. This was recognised by regulators in the United States and the European Union (appendix E).

⁷ The Rules do not contain any provisions directly addressing the market power of NEM participants. Instead, clause 3.1.4 (b) states that chapter 3 of the Rules (which sets out the market rules) is not intended to regulate anti-competitive behaviour by market participants, which is subject to the Competition and Consumer Act.

When merchant interconnectors in the NEM first began operations, they entered or, at least, envisaged entering into contracts to assign property rights to other parties. For example:

- Basslink and Hydro Tasmania are parties to a 25-year agreement known as the Basslink Services Agreement, under which Hydro Tasmania acquired the rights to inter-regional revenues earned by Basslink in exchange for a facility fee.
- When Murraylink Transmission Company registered as a MNSP, it proposed in its access undertaking to the ACCC to sell the rights to bid the Murraylink interconnector into the NEM and to earn the associated revenues. These rights were to be sold in the form of physical and financial contracts (ACCC 2002, p. 1)

However, there is currently a lack of clarity in the NEM as to whether merchant interconnectors can assign property rights. This is largely because the access arrangements applying at the time these merchant interconnectors began operations (the National Electricity Market Access Code, which the ACCC authorised under Part IIIA of the *Trade Practices Act* 1975), were superseded when the Rules were introduced on 1 July 2005.

In the AEMC's consideration of the rule change request concerning 'scale efficient network extensions' (AEMC 2011i, p. 5), some participants raised the absence of explicit property rights for merchant transmission.⁸ They claimed that a lack of property rights limited 'market-driven' options for building extensions, and that providing 'firm access' would increase investment in merchant transmission. Generally, these participants argued that any regulated framework should not crowd-out private investment. For example, the National Generators Forum, in response to the AEMC's draft rule determination, said:

- One of the major failings, in our view, of the transmission system is the inability of generators or investors to make private investments in transmission assets with any certainty that the value of that investment will not be captured by other beneficiaries or directly by new connections. ...
- The provision of property rights over merchant transmission has the potential to encourage greater investment in transmission by private investors (NGF 2010, pp. 4–5)

The AEMC is currently considering access rights for generators (and to MNSPs) as part of its transmission frameworks review (AEMC 2011b, 2012j, 2012n). In its stage 2 report (2012j, n), it set out two options for generator access to the regional reference price: 'non-firm access' — which is basically clarifying the status quo

⁸ These participants included the AER, Energy Australia, Macquarie Generation et al., National Generators Forum.

access arrangements — and ‘optional firm access’ — where generators can obtain financially firm access (as distinct from physical access) from a TNSP to their regional reference price through a compensation mechanism. (The options are described further in chapter 17 within the context of how they address disorderly bidding by generators.)

The AEMC’s optional firm access proposal is of relevance to merchant interconnectors in the following ways.

Intra-regional access. MSNPs use TNSP networks in the two regions that they interconnect. In the region from which they draw power (the exporting region) they are a demand-side user and so beyond the scope of the optional firm access. In the region into which they deliver power (the importing region), they are similar to a generator, in the sense that they inject power into the network at a specific node. Therefore, access provision to a MNSP in the importing region is the same as for a generator. A MNSP would then be able to decide how much firm access to procure using similar criteria to a generator.⁹

Inter-regional access. The AEMC’s proposal enables a generators and retailers to purchase firm access rights that entitle them to the price difference between two regions on their ‘access amounts’ (the amounts of power to be transported). This is similar to the payment from the current settlements residue auction instrument. However, that payment is reduced when a generator causes the interconnector to be constrained off, as the payment is dependent on actual flows. Under optional firm access, the generator causing this effect would compensate the inter-regional access holder to ensure that, despite the reduction in interconnector flow, the access settlement payment did not decline. Although access payments would still be scaled back if transmission capacity were reduced, holders of inter-regional access rights would receive a firmer payment than current holders of settlements residue auction instruments.

The AEMC’s proposal for optional firm access appears to be a step forward in enabling MSNPs to not only establish property rights over their merchant interconnectors, but to acquire them in respect of other parts of the transmission network.

⁹ A MNSP can flow power in both directions and so there are potentially two importing regions in which it might seek firm access.

20.3 Beneficiary pays

Apart from merchant interconnectors, another approach to investment in interconnectors is for the potential beneficiaries of an interconnector investment to propose and finance the investment themselves. The approach could apply through either commercial contracts or a regulated arrangement involving the identification of beneficiaries and mandated contributions to the investment in accordance with the benefits they receive. The interconnector could be operated as a regulated or a merchant interconnector.

Variants of this approach in relation to interconnectors or transmission lines have applied in Argentina (box 20.5) and New Zealand, and are currently reflected in the US Federal Energy Regulatory Commission's Order 1000.

In the NEM, a beneficiary pays approach already applies under the Rules to 'non-regulated transmission services', some 'negotiated transmission services' (which include 'connection services') and 'extensions'.¹⁰ These services can involve the connection of generators and other customers to the transmission network, which are paid for by non-TNSPs. For example, Grid Australia identified the following non-regulated transmission services paid for, and owned, by non-TNSPs:

- Davenport to Olympic Dam 275 kV line owned by BHP Billiton (South Australia)
- Smithton to Woolnorth 110 kV line owned by a generator (Tasmania)
- Goonyell Riverside Expansion 132 kV private network (Queensland) (Grid Australia 2012a citing PWC 2012, p. 18).

In its transmission frameworks review, the AEMC recommended a number of measures for improving arrangements for connecting generators and other customers to the transmission system (AEMC 2012j). Many of its measures are intended to clarify what are the Rules in this area (including the meaning of the above services). For example, the AEMC proposes to clarify the Rules to allow a connecting party (such as a generator or large load) to issue a tender for the provision of an 'extension' (which the AEMC describes as the lines and other equipment between the connecting party's facilities and the boundary of the assets used to provide the connection service such as a substation) or elements of that provision. A TNSP could participate in such a tender, but if requested by a connecting party must provide an extension as a negotiated transmission service, which has implications for the ownership and economic regulation of the extension.

¹⁰ Each of these terms are referred to in the Rules but, as the AEMC noted in its transmission frameworks review, are not all clearly defined.

Box 20.5 **The public contest method in Argentina**

The 'public contest method' for major transmission expansions was introduced in Argentina as part of major reforms to its electricity sector in 1992.

Although there were subsequent amendments to the public contest method, with its role being substantially diminished after 2002, its essential characteristics were:

- Beneficiaries, rather than incumbent transmission companies or regulators, propose, voted and paid for agreed major expansions.
- The system operator used an 'area of influence' method to identify beneficiaries of the expansions and the proportion in which each would have to share in the costs.
- The regulator still had to ensure that the proposed expansions met a 'golden rule' test, where the total cost of generation, transmission and unserved energy would be lower with the proposed expansions than without it.
- Where voted on and approved by a majority of the beneficiaries, a competitive tender was put out to build, operate and maintain the expansion. The tender contract specified an amortisation period in which beneficiaries had to pay for the expansion according to their use.
- After the expiration of the amortisation period in the tender contract, annual remuneration for the expansion followed the remuneration regime applicable to the existing network of the incumbent transmission company, which basically covered operation and maintenance only.

Papers reviewing the performance of the public contest method (for example, Littlechild 2011a, b; Littlechild and Skerk 2008d) found that:

- Criticisms that the public contest method did not work in relation to a 'much needed' Fourth Line were unwarranted. Although beneficiaries voted down an initial proposal, later research found that it was expensive, premature and uneconomic. In the short term, beneficiaries agreed to a cheaper alternative. When conditions later made the Fourth Line attractive, the beneficiaries 'worked well' to design, propose and pay for a line at a significantly lower cost than the initial proposal.
- The public contest method enabled substantial investment in better transmission control systems (series capacitors). These more than doubled transmission capacity limits, which was more than sufficient to meet the increased demand and were more economic than building new transmission lines.
- By 2007, around 40 public contest proposals for major expansions had been made, of which 35 were accepted by beneficiaries and all were implemented. The four largest approved expansions (not initiated by the Government) ranged from \$US25–\$US256 million.
- Bidding was generally competitive with tenders attracting an average of two to three bids. Independent companies won many of the contract tenders.

Sources: Littlechild (2011a, b); Littlechild and Skerk (2008a, b, c, d).

Some participants commented on the potential for a beneficiary pays approach, such as the Argentinian public contest method, to apply to interconnector investments. Hydro Tasmania said that:

... the most likely way of introducing their concepts is in the planning domain. The lead times between transmission and generation are mismatched and this means that generation has to follow in the general direction that transmission has set in relation to geography. The Argentinian approach would allow a more market based approach to planning by involving participants in making commitments to potential new investment. Some study would need to be undertaken in Australia to assess whether the lead times are such that this approach can work. (sub. 41, p. 5)

However, other participants were less supportive. For example, the National Generators Forum argued that:

... the “public contest method” and market based methods [are] more suited to simple, shared networks with few significant externalities and dedicated to few users. It may be suited also to shared connections in to a broader system. The NGF considers such approaches may well work in rail systems, such as the development of the coal rail network in Queensland and the Hunter Valley, where a few users can vote on proposed developments. Where the capital required is beyond the networking company then direct investment in infrastructure by users may also work, such as the Surat Basin rail system. By contrast the electricity network has over 20 million consumers (represented by their Regulators) and an array of suppliers (generators) of different types. A key problem with such approaches is competing objectives of users and instances where incremental costs are in excess of average costs of the system, pushing up costs for all users. (sub. 33, p. 8)

The AEMC suggested that a beneficiary pays approach would not be warranted if financial firm access rights were made available:

It is also not clear to the [AEMC] that consideration of radically different approaches, such as the Argentinian Public Contest method, is warranted. ... In the NEM, currently, generators are not seen as beneficiaries of network expansions. While the Commission considers that there is a case for considering changes to the arrangements for generators in the NEM, our current view is that the approach that might be of most benefit would be the provision of financial firm access rights. (sub. 16, p. 8)

Read (2012) argued that the beneficiary pays approach to transmission investment used in New Zealand in the 1980s had not worked well in practice. At the time, investment in transmission could proceed if and only if a beneficiary coalition agreed to pay for it (and accept financial transmission rights in return). Read noted the absence of an electricity sector regulator at the time, which meant that broadly binding agreements could not be enforced and that Transpower (the transmission network provider) was impelled to negotiate with a variety of parties. Read concluded that the beneficiary pays framework needs a ‘strong, independent, and

rigorously consistent’ regulator to coordinate the process and identify beneficiaries, represent ‘dispersed interests’ and make and enforce binding agreements.

In the Commission’s view, the main advantage of a beneficiary pays approach to interconnector investment would be that, in having to pay for the interconnector, beneficiaries would have strong incentives to get involved in the decision-making process and to ensure that the investment was the most cost-effective outcome.

However, there would be disadvantages associated with the approach were it to apply to interconnectors.

- If the approach was voluntary, there could be free-rider problems. There are potentially many beneficiaries from an interconnector — for example, many loads and many generators. All of them would have an incentive to defer paying for the interconnector in the hope that other beneficiaries value it enough to fund its development. Because of the incentive to free-ride, an interconnector might not be constructed in a timely manner or financed in a way that ensures its costs are efficiently allocated across all beneficiaries, or constructed to an efficient capacity.
- Even if a beneficiary pays approach was mandated (requiring the beneficiaries to pay), in a way similar to the Argentinian public contest method, identifying the beneficiaries, attributing benefits to each and allocating costs among them could be far from easy. For example, a usage-based method of allocating costs among beneficiaries may inadvertently discourage their full use of the transmission assets (in order that they be charged a lower cost share). Also, when the flow of power over an interconnector changes, so too do the beneficiaries, making it difficult to identify them in every case.
- There would also be the challenge of accounting for future beneficiaries who enter the NEM and allocating costs of the interconnector investment to them.

Accordingly, while there are conceptual advantages to a beneficiary pays approach, the Commission is not convinced that, in practice, a mandated approach akin to the Argentinian public contest method would be advantageous.

Having said that, the Commission’s proposal for a national planner approach to transmission expansions (draft recommendation 15.2) should be able to accommodate a *voluntary* beneficiary pays approach to interconnectors. Any party — for example, a generator, a load, a network business (or a consortium of parties) — should be able to voluntarily finance and operate a new interconnector (whether regulated or merchant) if it were commercially viable for them to do so. This proposal would, of course, need to satisfy necessary NEM-wide transmission planning and other requirements such as relating to reliability.

21 Governance

Key points

- Governance of the National Electricity Market (NEM) and its institutions is critical to achieving the National Electricity Objective through efficient electricity network regulation. It particularly affects network revenue and price determinations, network planning, and the speed of reform.
- Participants (and stakeholders) have concerns about aspects of the governance of the Australian Energy Regulator (AER), currently located within, and resourced through, the Australian Competition and Consumer Commission (ACCC).
 - AER surveys indicate that stakeholders do not appear to have a high level of confidence and trust in the regulator, and that their ratings of the regulator's performance and reputation have declined in recent years.
 - Some participants question whether the AER has sufficient resourcing, specialist expertise and capacity to fulfil its current and growing obligations. However, there is no publicly available information to assess these matters.
- Two immediate measures to improve the AER's governance, while retaining the regulator within the ACCC, are to:
 - undertake an independent review of the AER's resourcing and capacity
 - give the AER more control over its budget and resources, and make it more accountable (such as through a separate annual report) for how it manages those resources.
- A more far-reaching option would be to remove the AER from the ACCC and establish it as a separate independent entity — with full or partial funding from an industry (or NEM) levy. This raises complex issues upon which further input from participants is sought.
- The participation of consumers (such as households, small businesses and major industry users) in NEM policy, regulatory, rule-making and review processes is fragmented. There would be merit in a single consumer body having adequate public funding, and with expertise in economic regulation and energy markets. This body could participate in NEM processes and in negotiating settlements with network businesses.
- The powers of the South Australian Minister and the Australian Energy Market Commission should be amended to fast-track Rule changes proposed by appropriately undertaken reviews and agreed to by the Standing Council on Energy and Resources. This would hasten reform and reduce costs for, and consultation burdens, on stakeholders, while still providing appropriate checks and balances.

The governance of the National Electricity Market (NEM) and its institutions is critical to the:

- achievement of the National Electricity Objective (NEO)
- efficiency of current electricity network regulation, particularly in relation to making network revenue and price determinations, and network planning
- the pace of regulatory reform.

The governance of the NEM refers to the overarching policy and legal framework that sets out its objectives, regulates its operation, establishes and assigns functions to institutions, and sets out processes for its review and amendment. At the institutional level, governance is more narrowly concerned with how each relevant institution undertakes its functions including:

- how it is led
- how it interprets its objectives
- how it structures itself
- what priorities it sets for itself
- what analytical and technical approaches it adopts
- what internal corporate culture and values it promotes
- what staff competencies it seeks and rewards
- how it engages with stakeholders
- how it monitors the performance of its functions
- how and what it reports to governments and other stakeholders
- how it exercises any discretion
- whether it has processes for continuous improvement and change.

This chapter focuses on three areas of governance relating to electricity network regulation.

- The Commission has made recommendations in this report that will increase the regulatory responsibilities of the Australian Energy Regulator (AER). However, participants have raised concerns about how the AER manages its current functions, which has implications for its capacity to absorb new functions (section 21.1).
- The NEO is to promote efficient investment in, and efficient operation and use of, electricity services for the ‘long term interests of consumers’. Participants

have expressed concern about the poor engagement of consumer representatives in relation to electricity network regulation (section 21.2).

- The chapter concludes at section 21.3 by considering how the Commission's recommendations in this report, along with those arising from reviews outside of the Australian Energy Market (AEMC), might best be implemented under the current NEM policy and legal framework, and whether that framework lends itself efficiently to this task.

21.1 Governance of the Australian Energy Regulator

The AER is the national regulator of the wholesale electricity and gas markets. It was established in July 2005 as a statutory body under then *Trade Practices Act 1974* (now the *Competition and Consumer Act 2010*). It is funded by the Australian Government, with staff, resources and facilities provided by the Australian Competition and Consumer Commission (ACCC). The AER has three 'members' — two state members (including the chair) nominated by the Standing Council on Energy and Resources (SCER) and a Commonwealth nominated member who is required to be an ACCC commissioner. The Commission understands that it has around 140 staff, which accounts for 17 per cent of all ACCC staff.¹ The structure of the AER — including its links with the ACCC, the SCER, and two external review bodies — is set out in figure 21.1.

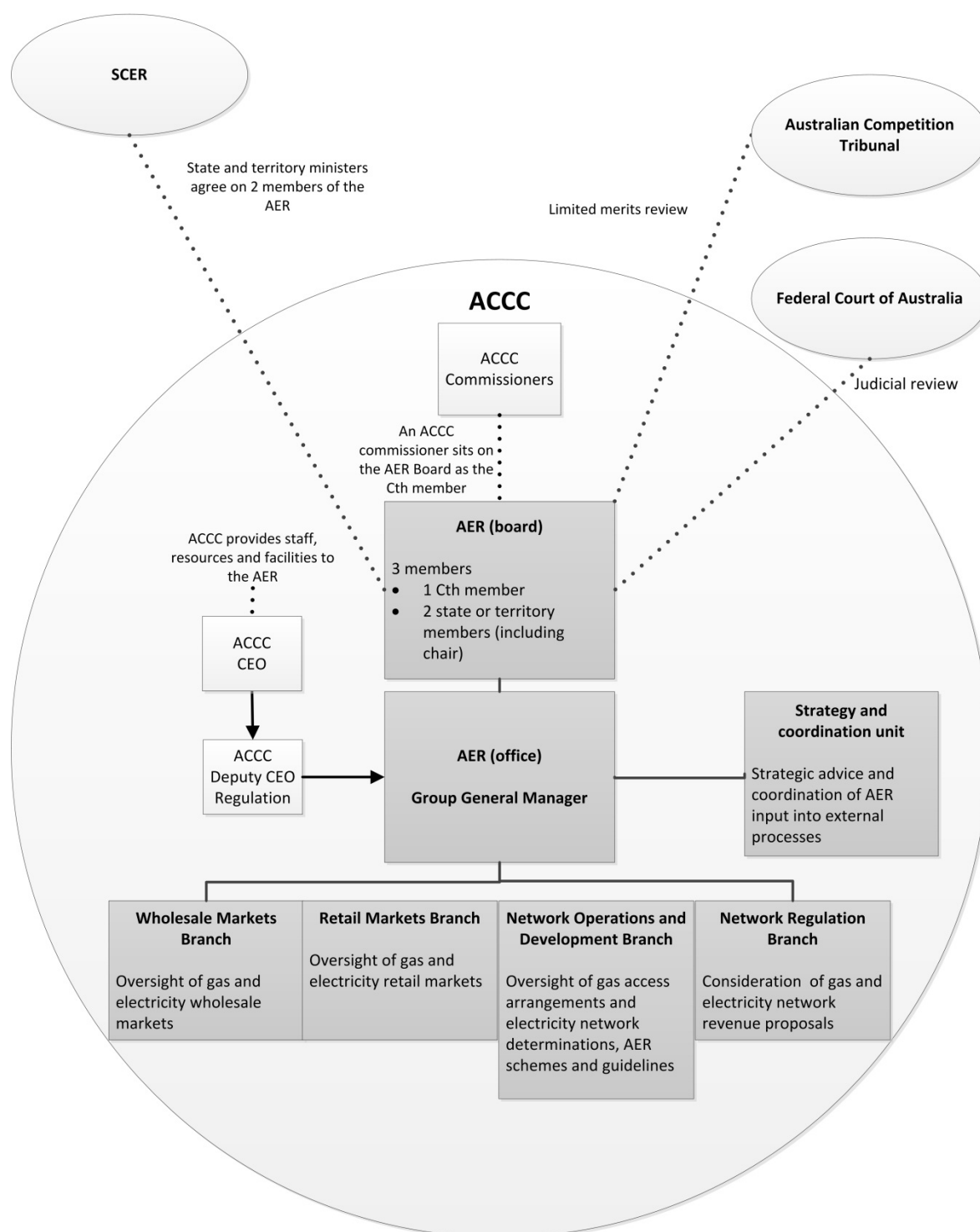
The AER's functions in relation to the NEM include:

- the economic regulation of electricity transmission and distribution network providers (including making revenue and price determinations)
- monitoring the wholesale electricity market to ensure compliance with the National Electricity Law, Regulations and Rules, investigating any breaches, and taking enforcement action where necessary
- preparing and publishing reports such as on the financial and operational performance of network service providers.

The AER was originally conceived by the Parer Review Panel in 2002 as an 'independent', 'separate energy sector-specific agency' (Parer et al. 2002, pp. 84, 86).

¹ AER, pers. comm. 11 August 2012. These are staff directly engaged in AER work. Around another 10 ACCC staff work indirectly on AER matters.

Figure 21.1 Structure of the Australian Energy Regulator



Data sources: ACCC and AER (2011); AER (2012k); SCER (2011c).

Nevertheless, the Ministerial Council on Energy (MCE) subsequently decided that, while the AER would be a ‘separate legal entity’, it would be a ‘constituent part’ of the ACCC (MCE 2003b, p. 5; MCE Standing Committee of Officials 2004a, p. 2).

When the AER was established, the inaugural chair, Steve Edwell, considered that the ‘legal construct’ of the AER as a ‘separate legal entity’, and its incorporation into the ACCC, would not affect the regulator’s independence :

... the AER’s legislation is unequivocal in terms of its independence and the AER will be responsible for making decisions on energy regulatory matters independently of the ACCC. The AER will have its own dedicated staff and other necessary resources and identity separate from the Commission. (Edwell 2005, p. 5)

Areas of concern

The establishment of the AER in 2005 was an essential step in creating a nationally consistent approach to the regulation of the energy sector, particularly of electricity networks. The benefits of having a national energy regulator were expressed by Edwell as follows:

Simply put, the key principle behind the establishment of the Australian Energy Regulator was that a national energy market needs a national energy regulator. Different approaches to regulating utilities across jurisdictions distort investment decisions and create unnecessary costs and barriers for utilities operating jurisdictional boundaries.

Despite the fact that gas and electricity has been traded across borders for some time now, giving rise to a national market in both sectors, there are still a dozen or so state and territory energy regulators. The AER will, over the next few years, replace jurisdictional regulators and become a “one stop shop” regulator for the energy sector on a national basis.

A single and independent regulator will reduce regulatory costs and uncertainty to business and allow both gas and electricity markets to develop along, as much as possible, a consistent regulatory framework. (Edwell 2005, p. 2)

However, seven years on, participants in this inquiry and in other reviews have raised concerns — some inter-linked — about the governance of the AER. In assessing these concerns, the Commission has drawn on several core principles, which it considers to apply to ‘good governance’ (box 21.1).

Box 21.1 **The Commission's principles of good governance**

During the Commission's work in regulatory benchmarking, and in other areas, a number of principles and leading practices have emerged that are relevant to ensuring the good governance of a regulator. These principles are that the regulator:

- has 'sound' objectives, such as to maximise community wellbeing or economic efficiency, which are prioritised where they conflict
- is independent and impartial in that its decisions and actions are not subject to the influence of any one stakeholder or group of stakeholders (including governments)
- has effective and strong leadership
- has a board of directors appointed on the basis of their independence, expertise and skills
- has staff with appropriate expertise and skills
- has adequate funding to fulfil its functions
- applies rigour and sound evidence in making decisions and taking actions
- keeps up to date with, and where appropriate, adopts international regulatory best practices and innovations, which improve the efficiency and effectiveness of regulation
- consults with the wider community in making decisions and taking actions
- has the trust and confidence of all its stakeholders
- is transparent about its decisions and actions
- is timely in its decisions and actions
- is accountable to others for its decisions and actions
- uses its resources efficiently to achieve its objectives
- is subject to periodical independent reviews of its capability and performance.

Stakeholders' confidence and trust

Many stakeholders currently have poor perceptions of the AER. The limited merits review panel recently said:

As a relatively young organisation, created in conjunction with a re-allocation of powers between States and the Commonwealth, the AER does not appear, on the basis of evidence given to the Panel, yet to enjoy a high degree of confidence and trust among many stakeholders. (Yarrow et al. 2012b, p. 47)

According to the 2011 Australian Energy Regulator Stakeholder Survey (figure 21.2), stakeholders' positive views about the AER have declined since 2008 in relation to:

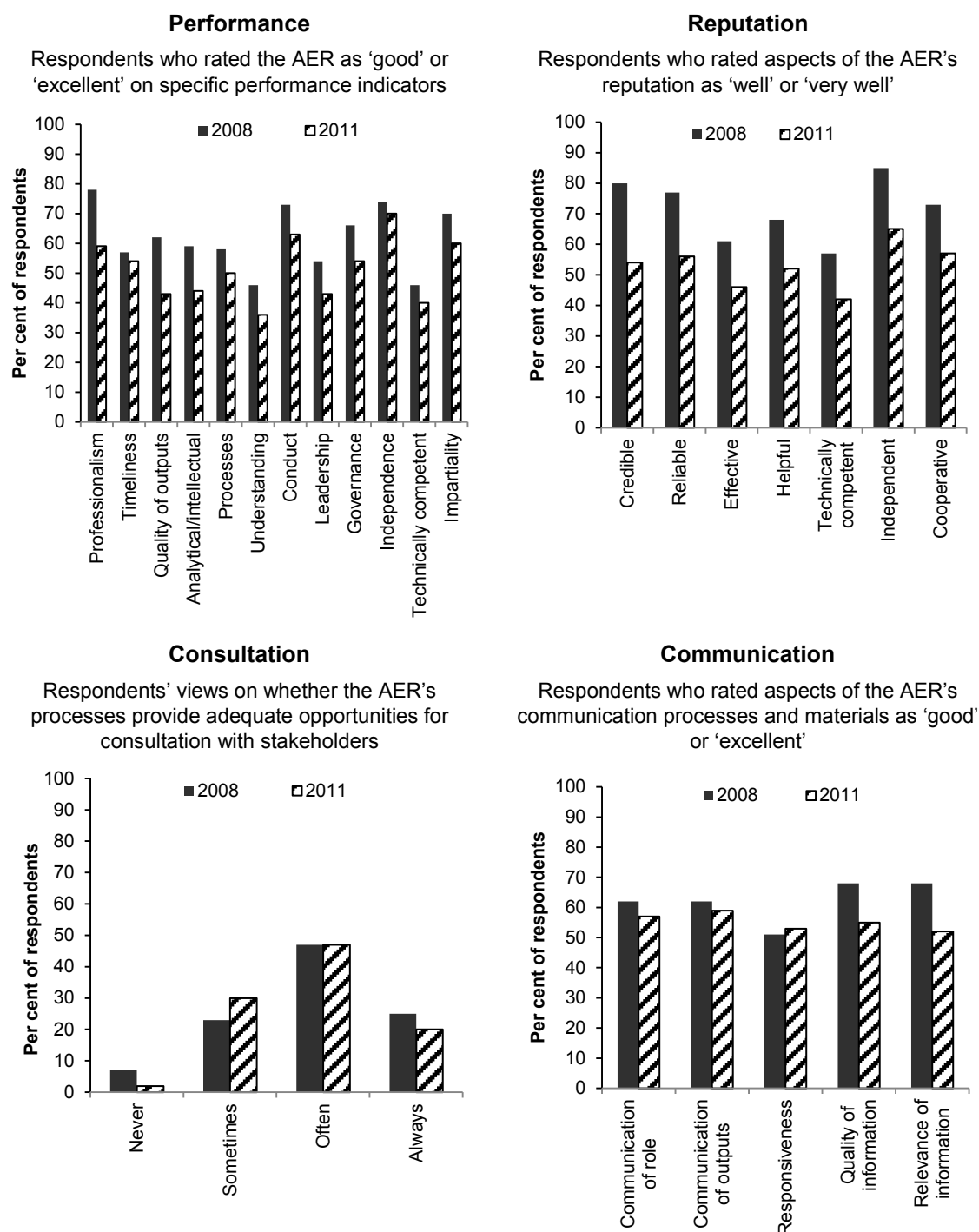
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- all 12 performance indicators, with ‘professionalism, ‘quality of outputs’ and ‘analytical/intellectual capacity’ experiencing the largest declines of all the indicators
 - all seven indicators of reputation, particularly in relation to the AER being ‘credible’, ‘reliable’ and ‘independent’
 - four of five indicators of communication processes and materials, particularly in relation to the ‘relevance’ and the ‘quality’ of the AER’s information.

The trends in the survey results are disturbing. When the survey was first undertaken, the AER was still a relatively new agency and likely to have faced teething problems. It might be reasonable to expect that the longer the AER operated, the more experienced it would have become in managing its functions and, thus, the more positive would have been the views of stakeholders. However, as the Energy Networks Association noted, ‘... the opposite seems to have occurred’ (sub. 40, p. 4).

The Commission has received other, largely confidential, evidence of poor stakeholder confidence and trust, which corroborates the Australian Energy Regulator Stakeholder Survey’s findings.

- Under the National Electricity Rules, the AER is responsible for acting as a neutral arbitrator and for making unbiased and objective determinations in the ‘long term interests of consumers’. However, some consumer groups believe that the AER should, and does, act as their ‘proxy’ in the determination process (Consumer Action Law Centre sub. 5, p. 2). Such views might colour other stakeholders’ perceptions of the AER’s independence, even though the regulator has asserted that it does not act in the interests of any particular party (AER 2012l, p. 7).
- The Commission has been told by various participants that the:
 - AER determination process is ‘combative and adversarial’, and lacking in consultation, with frequent ‘surprises’ arising from determinations
 - consultation process between UK distributors and Ofgem involves significant ongoing contact between the regulator and firms, whereas consultation between the AER and the network businesses occurs mainly between a network’s initial proposal and the draft determination, with very little interaction outside this period
 - AER is the ‘poor cousin of the ACCC’, in contrast to generally favourable comments about the AEMC.

Figure 21.2 Australian Energy Regulator Stakeholder Survey responses^a



^a The Australian Energy Regulator Stakeholder Survey, undertaken in 2008 and 2011, assesses stakeholder views about the AER in relation to four areas: performance, reputation, consultation, communication. The most recent survey allowed stakeholders to give feedback on these areas in relation to how the AER carried out the following three roles: monitoring, compliance and enforcement under national electricity and gas laws; preparing for responsibilities under the National Electricity Customers Framework (retail law); and electricity and gas network regulation. ^b The number of respondents in 2011 was 112 and in 2008 was 114.

Data source: Buchan (2011).

Resourcing and capacity

The AER needs adequate resources and capacity (including appropriate in-house specialist expertise) to undertake its functions effectively, including to apply rigorous analysis to its revenue and price determinations for network businesses. Should the Commission's recommendations be accepted, the AER will require additional resources to be effective.

Participants have expressed concerns that the current resourcing and capacity of the AER does not adequately support its current functions, let alone any expansion of these. For example, the Energy Users Association of Australia noted that network service providers:

... have been calling for more resources for the regulator in the context of the current debate about economic regulation of energy networks. This can be seen, for example, in their submissions to the AEMC on the AER's rule change proposals. (sub. 24, p. 10)

Some have claimed that the ACCC has an adverse influence on this capacity. The Energy Networks Association (sub. 40, pp. 1–2) also considered the following:

- The AER faces 'internal competition' for high quality staff from other 'high profile' parts of the ACCC. The consequences of this include 'rapid' staff turnover, the loss of specialist in-house expertise in the AER, a relative lack of stability and continuity within AER review teams, and relatively junior staff typically playing a significant role in the initial stages of AER determination processes.
- The lack of equivalent resources within the AER 'drives' a significant reliance on externally sourced specialist expertise, which does not add to the ongoing knowledge capital of the AER. This may be an unintended consequence of the AER being bound to employ staff on the same terms and conditions as ACCC staff and being subject to the same human resourcing challenges facing the Australian Public Service as a whole.
- Other energy regulatory bodies and institutions have been able to develop or have an in-house capacity of specialist expertise — for example, the UK Office of Gas and Electricity Markets (Ofgem) and the AEMC.

Grid Australia agreed that the AER should be strengthened and have more skills:

... What we are concerned about is a regulator that does not have the skills or capability and just gets it wrong. ... the industry expects [the regulator] to have the knowledge of the industry, not only the economic and legal, but also the engineering competence, and the ability to engage with businesses in a deep and constructive way to truly understand the businesses' needs and business cases. (2012b, p. 39)

Unfortunately, transparent information about the resourcing and capacity of the AER is not separately available to help assess these concerns. Information about the

AER's budget, the AER's in-house expertise, staff allocation across areas of the AER's work, and staff movement between the AER and ACCC is not on the public record.

Nonetheless, at least *prima facie*, it appears to the Commission that the resourcing and capacity of the AER to undertake its functions is currently inadequate. The lack of transparent information itself raises further concerns about the accountability and independence of the AER.

Errors

Participants raised concerns about errors in the AER's decisions identified by the Australian Competition Tribunal ('the Tribunal') in its limited merits reviews.²

AER decisions reviewable by the Tribunal include:

- revenue and price determinations for transmission and distribution in electricity (including application of regulatory test)
- decisions not to exempt entities from ring fencing guidelines or to impose additional ring fencing requirements in electricity.³

Based on its analysis of the applications by network businesses to the Tribunal since 2008 (when limited merits review commenced⁴), the Energy Networks Association (ENA 2012; sub. 40, p. 3) observed that the:

- Tribunal found material errors in many AER network revenue and price determinations, including 'recurring fundamental errors'
- material errors found by the Tribunal related to 'fundamental issues' such as the use of relevant evidence, the interpretation and application of accepted statistical techniques, and the application of logically consistent principles to derive conclusions from empirical evidence
- AER itself conceded errors on its part in more than one-third of over 60 specific matters raised in the appeals to the Tribunal.

² Applicants seeking a limited merits review of an AER decision must establish grounds of review based on regulatory errors of fact or discretion and demonstrate there is a serious issue to be heard.

³ Other AER decisions subject to limited merits review are decisions to draft and approve (or revise) gas access arrangements and ring fencing decisions in gas.

⁴ Previously, decisions by the Tribunal involved a complete rehearing or reconsideration of the matter considered by the designated Minister or arbitration by the ACCC (COAG Reform Council 2011, p. 259).

Information provided by the Australian Government Solicitor to the limited merits review panel also shows the extent of errors found by the Tribunal in AER (electricity and gas) decisions not involving weighted average cost of capital (WACC) parameters (table 21.1). Applications to the Tribunal since 2008 appealed some 50 elements of those decisions. The AER conceded errors in five elements. Around 21 elements appealed were affirmed by the Tribunal, with the remaining 25 elements varied by the Tribunal or remitted to the AER.

Table 21.1 Tribunal cases involving non-WACC parameters in AER electricity and gas decisions, January 2008 to February 2012

<i>Application to the Tribunal by:</i>	<i>Date of Tribunal judgment</i>	<i>No. of elements appealed</i>	<i>No. of elements remitted or varied</i>	<i>No. of elements affirmed</i>	<i>No. of elements conceded by AER</i>
United Energy Distribution	6 Jan 2012	14 ^a	7	6	2
Envestra Ltd	11 Jan 2012	2	1	1	0
Jemena Gas Networks (NSW)	25 Feb 2011	5	2	3	0
Ergon Energy Corporation Ltd (Service Target Performance Incentive Scheme) (No. 5)	24 Dec. 2010	1	0	1	0
Ergon Energy Corporation Ltd (Non-system Property Capital Expenditure) (No. 4)	24 Dec 2010	1	1	0	0
Ergon Energy Corporation Ltd (Labour Cost Escalators) (No. 3 and No. 9)	24 Dec 2010 10 Feb 2011	3	2	1	0
Ergon Energy Corporation Ltd (Customer Service Costs) (No. 2)	24 Dec 2010	1	0	1	0
Ergon Energy Corporation Ltd	13 Oct 2010	1	1	0	0
ETSA Utilities	13 Oct 2010	1	1	0	0
United Energy Distribution	23 Dec 2009	1	1	0	0
Energy Australia and Others (No.1 and No.2)	12 Nov 2009 25 Nov 2009	4	3	1	1
Energy Australia	16 Oct 2009	11	5 ^b	6	2
ElectraNet Pty Ltd (No. 3)	30 Sept 2008	2	1	1	0

^a The finding of the Tribunal in relation to one element is unknown for confidential reasons. ^b Although the Tribunal affirmed the AER's decision in 4 elements, it suggested the AER may reconsider the issue on remittal.

Source: Yarrow et. al. (2012b, annex 1).

Examples of the elements varied or remitted, included errors by the AER in its:

- methodology for indexing the regulatory asset base for inflation (United Energy Distribution, 6 January 2012)

-
- rejection of the applicant's claim for an addition to be made to its regulatory asset base in respect of easements extant as at 1 July 1999 (ETSA Utilities, 13 October 2010)
 - calculation of 'other' operating expenditure in relation to public lighting (Energy Australia, 16 October 2009).

However, some caution is needed in drawing strong conclusions about the degree to which this reflects a lack of rigor (as some claim).

- There is a selection bias associated with appeals cases. Because of the costs involved, applicants are unlikely to appeal any case that does not have a good prospect of success. Hence, any cases that are appealed are likely to represent a high likelihood that an AER error was made, rather than the reverse.
- Appeals cases typically represent a tip of the iceberg of all AER decisions (that are potentially subject to review by the Tribunal).
- The Tribunal can look at particular components of an AER decision without considering other related components. Had the Tribunal taken a more holistic approach, sometimes the AER's aggregate estimate may have been seen to have been reasonable (which may be a better measure of error).

A model litigant?

Another area of concern, flagged by the limited merits review panel, is the degree to which the AER has used its powers under the National Electricity Law, in relation to reviews of its decisions by the Tribunal, to raise:

- (a) a matter not raised by the applicant or an intervener that relates to a ground for review, or a matter raised in support of a ground for review, raised by the applicant or an intervener;
- (b) a possible outcome or effect on the reviewable regulatory decision being reviewed that the AER considers may occur as a consequence of the Tribunal making a determination setting aside or varying the reviewable regulatory decision.
(s. 71O (1))

The limited merits review panel described the 'puzzle' of why the AER abstains from exercising its powers as follows:

A major question that has arisen in the context of evaluating the operation of the [limited merits review] to date is: *why has the AER systematically declined to use its s. 71O (1) powers in electricity (s. 258 (1) powers in gas), even in circumstances where it was manifestly the case that (a) the matters being appealed were economically related to other aspects of the AER's determinations which were not being appealed, and (b) decisions on the contested matters could be expected to have very significant implications for the long term interests of consumers.* (Yarrow et. al. 2012b, p. 59)

In its submission to the limited merits review panel, the AER stated that its role in reviews is to ‘actively and objectively’ assist the Tribunal.

In doing so, the AER does not act as a protagonist. Instead, it acts to ensure that all relevant issues are canvassed before and understood by the Tribunal. (2012b, p. 9)

The AER’s usual practice is to make submissions to the Tribunal that:

- explain the Tribunal’s functions and powers and the relevant procedures and processes
- adduce evidence and present its view where it does not agree there is an error
- promptly concede where it agrees there is an error, to minimise the time and expense incurred before the Tribunal
- raise issues of public interest with the Tribunal.

The AER considers this role as ‘appropriate’ given the National Electricity Law and the National Gas Law, and the obligation on it to act as a ‘model litigant’ (2012b, p. 9). However, while the above role is consistent with the notion of a model litigant (box 21.2), a requirement to be a model litigant does not appear to rule out the proper defence of a position (Lee 2006, p. 10). The question then is whether the AER has the ability to use its prerogative under s. 71O (1) of the National Electricity Law (and its equivalent provision in the National Gas Law).

The limited merits review panel sought ‘authoritative legal advice’ from the Australian Government Solicitor as to why s. 71O (1) of the National Electricity Law and the equivalent section in the National Gas Law have not been used ‘more actively’ by the AER (Yarrow et. al. 2012b, p. 65). The Australian Government Solicitor was of the opinion that the sections do not enable the scope of a review before the Tribunal to be broadened by the AER or the Tribunal itself to encompass additional grounds of review.

Paragraph (a) permits the original decision maker to raise a ‘matter’ not otherwise raised. However, the matter must ‘relate[] to’ a ground for review ‘raised by’ the applicant or intervener. Paragraph (b) permits the original decision maker to raise ‘a possible outcome or effect’ of the Tribunal setting aside or varying the original decision, but similarly does not broaden the basis (that is, the grounds) on which the Tribunal might set aside or vary the decision or decisions under review. (AGS 2012, p. 6)

The limited merits review panel will be considering the issue further in its final report to SCER (Yarrow et. al. 2012a, 2012b).

Box 21.2 The Australian Government's model litigant provisions

The obligation

1 Consistently with the Attorney-General's responsibility for the maintenance of proper standards in litigation, the Commonwealth and its agencies are to behave as model litigants in the conduct of litigation.

Nature of the obligation

2 The obligation to act as a model litigant requires that the Commonwealth and its agencies act honestly and fairly in handling claims and litigation brought by or against the Commonwealth or an agency by:

- (a) dealing with claims promptly and not causing unnecessary delay in the handling of claims and litigation
- (aa) making an early assessment of:
 - (i) the Commonwealth's prospects of success in legal proceedings that may be brought against the Commonwealth; and
 - (ii) the Commonwealth's potential liability in claims against the Commonwealth
- (b) paying legitimate claims without litigation, including making partial settlements of claims or interim payments, where it is clear that liability is at least as much as the amount to be paid
- (c) acting consistently in the handling of claims and litigation
- (d) endeavouring to avoid, prevent and limit the scope of legal proceedings wherever possible, including by giving consideration in all cases to alternative dispute resolution before initiating legal proceedings and by participating in alternative dispute resolution processes where appropriate
- (e) where it is not possible to avoid litigation, keeping the costs of litigation to a minimum, including by:
 - (i) not requiring the other party to prove a matter which the Commonwealth or the agency knows to be true
 - (ii) not contesting liability if the Commonwealth or the agency knows that the dispute is really about quantum
 - (iii) monitoring the progress of the litigation and using methods that it considers appropriate to resolve the litigation, including settlement offers, payments into court or alternative dispute resolution, and
 - (iv) ensuring that arrangements are made so that a person participating in any settlement negotiations on behalf of the Commonwealth or an agency can enter into a settlement of the claim or legal proceedings in the course of the negotiations
- (f) not taking advantage of a claimant who lacks the resources to litigate a legitimate claim
- (g) not relying on technical defences unless the Commonwealth's or the agency's interests would be prejudiced by the failure to comply with a particular requirement
- (h) not undertaking and pursuing appeals unless the Commonwealth or the agency believes that it has reasonable prospects for success or the appeal is otherwise justified in the public interest, and
- (i) apologising where the Commonwealth or the agency is aware that it or its lawyers have acted wrongfully or improperly.

Source: AGS (2005).

The way forward

The Commission understands that the ACCC/AER is aware of many of the above areas of concern — particularly in relation to its resourcing and capacity — and appears to be taking measures to address them.

At its October meeting, the SCER (2012) has commenced a discussion on options relating to ‘institutional governance and funding’. All ministers agreed that the AER, however structured, should have sufficient capacity to manage the enhanced role envisaged through the current reform processes. There was ‘strong support’ from a number of ministers for structural separation of the AER from the ACCC.

The Commission notes that, as some of the areas of concern about the AER’s governance are inter-linked, an option intended to address one area of concern may also address another. For example, improving the resourcing and capacity of the AER may not only enable it to be more effective in undertaking its functions, it can lift stakeholders’ confidence and trust in the regulator.

The remainder of this section considers two broad options in relation to the AER’s governance:

- options for improving the resourcing, independence and accountability of the AER while retaining it within the ACCC
- options involving the separation of the AER from the ACCC.

Options for improvement while retaining the Australian Energy Regulator within the Australian Competition and Consumer Commission

One option is to integrate the AER completely within the ACCC and to abandon having an independent specialist energy regulator. However, the Commission considers that this option, although possible, is not likely to lead to significantly improved outcomes in terms of addressing the areas of concern discussed earlier.

The Commission considers there are two other credible options for improving the governance of the AER, while retaining it within the ACCC, which should occur immediately.

An independent review of the resourcing and capacity of the Australian Energy Regulator

As an important step, the Commission considers that there should be an independent small-scale and quick review of the resourcing and capacity of the AER to undertake all its functions, including with respect to the gas market.

The review should, among other things, examine:

- resourcing of the AER from the ACCC — its budget, staffing, and other resources
- staffing matters such as the AER's capacity to recruit appropriate specialist expertise, work allocation, staff competencies in relation to the performance of the AER's role, staff turnover within the AER, and staff movement between the AER and ACCC
- remuneration conditions offered by the AER (particularly, compared with the AEMC) to attract and retain the specialist expertise necessary to perform its role
- the extent of cost savings and other benefits from the AER being located within the ACCC
- whether current approaches to resourcing impede the AER's effectiveness
- options for improvement.

The review should involve consultation with AER board members and staff, ACCC commissioners and staff, and external stakeholders.

The review panel should consist of a small group of senior and experienced persons drawn from outside of the ACCC/AER with an appropriate understanding of the competencies required to undertake utility regulation and, particularly, electricity network regulation. Including in the panel persons with international experience of similar regulators could be helpful.

DRAFT RECOMMENDATION 21.1

There should be an independent review of the resourcing and capacity of the Australian Energy Regulator to undertake all its functions, including whether there are impediments to its performance and options for improvement.

Measures to improve the Australian Energy Regulator's independence and accountability

Since a review of the AER's resourcing and capacity is likely to take time, the Commission believes that some immediate 'no regrets' measures should be taken. While retaining the AER within the ACCC, these measures would give the regulator greater independence and, at the same time, make it more accountable for how it manages its resources.

- Giving the AER administrative control over its own budget, which would need to be adequate for it to manage its functions effectively, including acquiring developing and retaining the necessary specialist expertise. This might require negotiating with the ACCC to pay for corporate services and other 'overheads'.
- Requiring the AER to submit a separate annual report from that of the ACCC.
- Ensuring that the AER publicly reveals its strategy for improving its performance, including how it intends to address concerns from stakeholders that become apparent from the Australian Energy Regulator Stakeholder Survey. This includes providing milestones against which to assess whether the strategy was working.
- Enabling the AER (where it sees merit in this approach) to independently negotiate resource sharing arrangements with other relevant agencies, not just the ACCC. Other agencies could include NEM institutions such as the AEMO and AEMC, as well as state and territory utility regulators such as the New South Wales Independent Pricing and Regulatory Tribunal and the Victorian Essential Services Commission.
- Ensuring that the AER has the resources and capacity to establish and retain specialist expertise to carry expanded functions recommended by the Commission in relation to benchmarking (draft recommendation 8.6).
- Ensuring that the AER has regular ongoing communication and interaction with network businesses, their customers and other relevant stakeholders.

DRAFT RECOMMENDATION 21.2

The Australian Energy Regulator should have greater control over, and accountability for, the resourcing and management of its functions. It should:

- ***have its own separate budget sufficient to meet its role***
- ***submit a separate annual report of its performance***
- ***publicly reveal its strategy for improving its performance***

-
- *have an independent capacity to negotiate resource sharing arrangements with a range of agencies, not just the Australian Competition and Consumer Commission*
 - *ensure that it establishes and retains the necessary specialist expertise to competently carry out its role, in accordance with draft recommendation 8.6*
 - *develop a program for regular ongoing communication and interaction with network businesses, their customers and other relevant stakeholders, with those interactions not just confined to periods of regulatory determinations.*

Options involving the separation of the Australian Energy Regulator from the Australian Competition and Consumer Commission

The options above, although seen as essential and capable of being implemented immediately, would not redress the impression amongst some stakeholders that the AER is ‘Commonwealth-centric’, and likely to be resource constrained due to ongoing budgetary pressures, as the AER would still be funded by the Australian Government. Nor would the options address all concerns about the influence of the ACCC on the AER, including on its culture and attitudes.

An option that would involve more substantial changes to the governance of the AER would be to separate it from the ACCC and merge it with the AEMC to create a single agency responsible for rule making, market development, and regulatory monitoring for compliance and enforcement (similar to the UK Ofgem).

Such a merger could promote closer interaction, communication and coordination between the ‘regulators’ and the ‘rule makers’, which could lead to better quality rules and decisions being made. Currently, lack of coordination and overlap of AEMC and AER activities has been seen as problematic (for example, Grid Australia 2012c, p. 5).

However, this option raises conflicts of interest for the rule makers in the merged agency — for example, they may be influenced to make rules that ease the task of the regulators in the agency, rather than being beneficial for the wider community. Indeed, the Commission believes that the clear separation of roles — with the SCER being responsible for policy, the AEMC being responsible for rule making and the AER being the regulator — is good practice and should not be compromised.

Accordingly, the Commission does not propose the option of a merger between the AER and AEMC. Indeed, concerns about coordination and overlap in the activities

of the AEMC and the AER might be better addressed under the current Memorandum of Understanding between the ACCC, AEMC and AER (2009).

However, in relation to the current inquiry, the Commission seeks participants' input on the separation of the AER from the ACCC and establishing it as a new separate entity funded by an industry (NEM) levy. An independent and separate national regulator was envisaged by the Parer Review Panel in 2002, with 'industry funding' proposed later by the MCE in 2003. The following discusses this option in two parts.

Establishing the Australian Energy Regulator as an independent separate entity

This option would remove the AER from the ACCC and reconstitute it as an independent and separate national regulator with appropriate governance arrangements (that meet the principles in box 21.1) and a budget that allowed it greater scope to have access to internal and external specialist expertise.

Implementation could occur by way of:

- enacting new South Australian legislation akin to the *Australian Energy Market Commission Establishment Act 2005*, or
- amending the Competition and Consumer Act, which currently establishes the AER.

The AER could, where appropriate, negotiate arrangements with the ACCC, AEMC, AEMO and other relevant organisations, to share resources such as: offices, payroll services, and information and communications technology services; and professional staff.

This option would involve a range of tradeoffs that need to be carefully weighed. On the one hand, the current arrangement of retaining the AER within the ACCC has the following advantages.

- It enables a consistent and co-ordinated multi-sectoral approach to the economic regulation of infrastructure — not just to electricity networks, but also to gas, water, postal services, rail services and telecommunications. As Dassler et. al noted:

In contrast [to Ofgem and other sector-specific regulators], if, for example, the Australian model of relying on a quasi-independent regulatory authority to act as regulator for a variety of regulated entities had been adopted in the UK, a common set of resources and benchmarking expertise could have evolved for application across a number of regulated industries. Such a concentration of expertise might have had the advantage of allowing lessons learned in one industry to be better applied in other industries than is the case at present. (2006, p. 172)

Indeed, many other state and territory regulators (such as the New South Wales Independent Pricing and Regulatory Tribunal and the Victorian Essential Services Commission) are responsible for a range of infrastructure industries.

Having said that, there may also be value in having competing approaches in methods of analysis — this could lead to innovation and improvements.

- There are resource sharing benefits for the AER in that the ACCC can quickly provide staff to the AER when demands upon the regulator become ‘peaky’. This is likely to occur during revenue and price determinations. Although there are clear benefits, it might contribute to the perception of some stakeholders about staff working in the AER on determinations with little or no background in the electricity sector. The Commission understands that the AER might need more staff with lower average utilisation if the regulator had to handle these tasks on a stand-alone basis.

Arguably, however, peak demands could be addressed by way of resource sharing arrangements with relevant agencies having the necessary expertise, not just with the ACCC, or by changing the scheduling of revenue and price determinations.

- There would appear to be real synergies between the two organisations. The ACCC should be able to benefit from the AER’s advice and input on energy sector competition and consumer protection matters. The AER, in turn, should be able to gain from intellectual inputs on the weighted average cost of capital and benchmarking technical matters from a special ACCC-wide analytical branch.

However, were the AER to be separated from the ACCC, it could be argued that some current synergies with the ACCC could still be retained. For example, the AER, could still continue to interact with the ACCC (as well as other relevant regulators) in coordinating regulatory groups — such as the Infrastructure Consultative Committee and the Utility Regulators Forum — as well as in arrangements to share professional staff.

- Retaining the AER within the ACCC addresses the risks of ‘regulatory capture’ of industry regulators. Regulatory capture is where the regulator identifies with the interests of the industry.

However, even as a stand-alone entity, these risks could be mitigated to the extent that, in addition to its network regulation functions, the AER also has regulatory functions in gas (sometimes a substitute to electricity), generation (where there are concerns about connection with transmission networks) and retail (through the adoption of the National Electricity Customer Framework). Further mechanisms to reduce the risks of capture include: the creation of a consumer body (draft recommendation 21.3), which would be expected to be

active in the AER's regulatory processes; an AER with appropriate governance arrangements such as an appropriately constituted board; and secondments and exchanges of AER senior managers with counterpart international regulators.

- There are pragmatic concerns about separating the AER from the ACCC. There would be establishment costs associated with separating the AER and the ACCC such as relating to enacting or amending legislation, developing a new organisation structure, making staff appointments, and establishing payroll and information technology systems. Also, the Australian Government, concerned about the proliferation of small agencies, has previously taken measures to reduce their number.

On the other hand, there are potential advantages in removing the AER from the ACCC.

- Although the AER and the ACCC have commonalities, electricity (and gas) network regulation involves unique and complex conceptual challenges. Arguably, it requires more prescriptive detailed regulation (befitting the natural monopoly status of networks), than some other forms of infrastructure. It could be said that the most important links for the AER are not to the ACCC, but to the AEMC, AEMO and the various other electricity and gas regulators around Australian and globally.
- The ACCC faces a difficult balancing act in its role as an economic regulator and as a competition watchdog and a consumer protection regulator. A senior ACCC executive acknowledged that, along with the benefits of a 'multi-sectoral body', there are 'significant challenges' including that:

Governance and decision making needs to be provided in a framework that manages the various risks inherent in a multi-sectoral body such as the ACCC (Pearson 2011, p. 9)

A senior advisor to the ACCC considered there was a confusion of roles in utility regulators, such as the ACCC and AER:

At present there is some confusion whether a utility regulator in Australia should act on behalf of customers, soliciting and promoting their views, or whether it should objectively weigh and assess the claims of both parties — playing the role of an independent arbitrator. This is particularly an issue for the Australian Competition and Consumer Commission ('ACCC') which plays a consumer protection role in other sectors. The combination of increasing political pressure on utility prices, combined with weak and ineffective representation from consumer groups, is leading to increased pressure on regulators such as the ACCC and the Australian Energy Regulator (AER) to exercise a customer protection role. ... customer advocacy and independent arbitration are two distinct roles which should be performed by two different entities. Public utility regulators in Australia should play the role of the arbitrator, not the consumer advocate. (Biggar 2011b, p. 7)

A particular risk is that the ACCC's roles as competition watchdog and consumer protection regulator can spill over and affect its approach to its role, and that of the AER, as an economic regulator of infrastructure. In the former roles, the ACCC prosecutes civil or criminal offences, such as those associated with deception or anticompetitive conduct, and is inevitably (and appropriately) adversarial. In contrast, the role of an economic regulator of networks is quite technical in nature, with a requirement for extensive ongoing consultation and communication with the businesses it regulates and other stakeholders, rather than being adversarial. As noted earlier, participants have already expressed concerns about the combative approach of the AER and the lack of consultation.

Funding the new entity through an industry (or National Electricity Market) levy

An alternative to full Australian Government and/or state and territory government funding of an independent AER is to enable the regulator to recover its costs in part or full from an industry (or NEM) levy. (Such a levy might also be considered as a source of funding for the AER were it to remain within the ACCC.)

The option of full funding of the AER (and the AEMC) through 'appropriate industry levies' was recommended by the MCE in 2003. Although a consultation paper was subsequently released (MCE Standing Committee of Officials 2004b), this option did not eventuate, although the reasons for this are not apparent.

Several Australian utility regulators — such as the Victorian Essential Services Commission, the New South Wales Independent Pricing and Regulatory Tribunal, and the ACT Independent Competition and Regulatory Commission — currently recover some of their costs of providing regulatory services through mechanisms such as levies (licence fees, and charges) on regulated businesses. For example, the ACT Independent Competition and Regulatory Commission imposes an 'energy industry levy' to recover the amount of its 'national and local regulatory costs'⁵ in relation to energy industry sectors as well as a licence fee on 'prescribed energy utilities' not covered by the levy (ICRC 2012). AEMO is currently fully funded from energy market participants.

Beyond the utility — and energy — sector, there are many other Australian examples of industry funding of national regulators. The Civil Aviation Safety Authority is fully funded from the aviation industry through fees for over 260 regulatory services, including licences and ratings, examinations, medicals and aircraft registration (CASA 2012). And the National Offshore Petroleum Safety and

⁵ The 'national regulatory cost' relates to the ACT's obligations under the Australian Energy Market Agreement to contribute to funding the AEMC and the SCER.

Environmental Management Authority is fully funded from offshore petroleum industry through a range of levies and fees including ‘safety case’ levies, well levies and an environmental plan levy (NOPSEMA 2012).

There are several potential advantages in shifting the full funding of the AER from the Australian Government’s budget to full or partial funding from an industry levy.

- Even if the initial costs were borne by NEM participants, the ultimate incidence of a levy would fall on end users of energy — a reasonable outcome for an economic regulator. The cost per customer would be very small.
- A levy coupled with the removal of the AER from the Australian Government might allow the regulator to have a remuneration policy that is more flexible than that of the Australian Public Service, and more consistent with the needs of being able to attract and retain the necessary specialist expertise required to fulfil the AER’s role.
- Partial funding through an industry levy, supplemented with some Commonwealth funding, would still enable the Australian Government to demonstrate its financial commitment, and to have a stake in regard to the regulation of national energy markets.

However, there are potential concerns about an industry levy.

- The Commission understands there might be constitutional legal issues relating to an industry levy. It might be seen as discriminatory — between those jurisdictions within the NEM and those that are not (that is, Western Australian and the Northern Territory).
- There might also be perceptions that the independence of the AER would be impaired if it were industry-funded, even though the levy could be imposed as part of the NEM settlements process administered by AEMO (rather than directly on businesses themselves).

The Commission seeks participants’ views on the costs and benefits of the following measures concerning the location and funding of the Australian Energy Regulator compared with the arrangements proposed in draft recommendation 21.2:

- *removing the Australian Energy Regulator from the Australian Competition and Consumer Commission and creating a fully independent agency*
- *funding the Australian Energy Regulator through an industry (or National Electricity Market) levy.*

21.2 Consumer engagement and representation

The NEO refers expressly to the ‘long term interests of consumers’.

Consumer groups collectively represent a diverse array of interests — including large industrial users, household consumers, and low income and vulnerable consumers. (Indeed, the term ‘consumer’ is hereafter used to cover all these groups of electricity customers.) Many of the consumer groups are small with most funded from a mix of public and private sources. While the larger industrial customer groups are focused on energy policy, the groups representing households have a broader interest in consumer policy and generally represent low income and vulnerable consumers.

Consumer groups have traditionally been involved at various stages of electricity network regulation — primarily, in attempting to decrease network prices or to develop better arrangements for disadvantaged consumers. They have proposed changes to the National Electricity Rules, submitted to AER network determinations, and participated in Tribunal reviews.

Each of the NEM institutions has some mechanism in place for consulting with consumers (and other stakeholders). For example, the AER has a Customer Consultative Group (consisting of 10 consumer advocacy groups) to provide it with advice on issues affecting energy consumers that fall within the scope of the AER’s functions under the National Energy Retail Law and National Energy Retail Rules. Its consultation with consumers on transmission and distribution pricing issues, however, occurs through individual determination processes, except where there are issues of ‘national significance’ (AER 2012m).

While not a consultative or advocacy body in its own right, the industry-funded Consumer Advocacy Panel (box 21.3) provides grants for consumer advocacy and research for the benefits of consumers of electricity or natural gas. This Panel was established under the *Australian Energy Market Commission Establishment Act* to promote the interests of all energy consumers, particularly small to medium consumers. The Panel’s electricity-related functions are funded by a fee levied by AEMO on NEM participants. In 2010-11, the Consumer Advocacy Panel allocated grants of around \$450 000 for electricity advocacy, around \$225 000 for electricity research, and over \$1.4 million for joint electricity and gas advocacy/research and capacity building (table 21.2).

Box 21.3 **The Consumer Advocacy Panel**

The Consumer Advocacy Panel is an independent body established under the Australian Energy Market Commission Establishment Act.

The Panel's functions include:

- identifying areas of research that would be of benefit to consumers of electricity or natural gas (or both)
- developing, and submitting for the approval of the SCER, guidelines for the allocation of grants for consumer advocacy projects and research projects for the benefit of consumers of electricity or natural gas (or both)
- preparing, and submitting for the approval of the SCER, annual budgets for the allocation of grants for consumer advocacy projects and research projects for the benefit of consumers of electricity or natural gas (or both)
- determining (subject to the approved guidelines and the approved budget) how grants for consumer advocacy projects and research projects for the benefit of consumers of electricity or natural gas (or both) are to be allocated
- preparing, and submitting for the approval of the SCER, guidelines for the assistance of applicants for grants for consumer advocacy projects and research projects for the benefit of consumers of electricity or natural gas (or both)
- publishing on the Panel's website and in other appropriate ways the results of research supported by a grant and other research of interest to consumers of electricity or natural gas (or both).

The Panel may, in performing its functions with respect to the allocation of grants — initiate its own research projects to be funded through the provision of grants; invite or accept applications for grants from other persons or bodies.

The objectives of the Panel in performing its functions are to —

- have regard to any relevant objectives set out in a National Energy Law, and
- promote the interests of all consumers of electricity or natural gas while paying particular regard to benefiting small to medium consumers of electricity or natural gas.

The Panel consists of a chair and four other members appointed by the Minister on the recommendation of the SCER.

The Panel must submit an annual report to the AEMC, which is published as part of the AEMC's annual report.

The AEMC and AEMO are responsible for funding the advocacy and research grants and administrative costs of the Panel. The AEMC is responsible for those functions of the Panel related to consumers of natural gas. The AEMO is responsible for functions relevant to consumers of electricity.

Sources: AEMC (2011j, k).

Table 21.2 Consumer Advocacy Panel grants, electricity-related, 2010–11

<i>Applicant</i>	<i>Approved project</i>	<i>\$ grant</i>
Electricity advocacy		
Australian Council of Social Service (ACOSS)	Revised grant to support travel costs for consumer representatives on the National Smart Meter Working Groups	3 390
Queensland Council of Social Service (QCOSS)	Submission to Queensland Competition Authority Benchmark Retail Cost Index draft decision	10 000
Ethnic Communities Council of NSW	NEM Advocacy 2010-11	22 000
Alternative Technology Advocacy	Consumer representation on the National Smart Metering Program National Stakeholder Steering Committee	23 315
St Vincent de Paul Society NSW and Vic	NSW tariff-tracking tool	38 587
ClimateWorks Australia	Cogeneration portfolio project: designing solutions to unblock barriers	40 000
Manningham City Council (representing the Street Lighting Group)	Appeal against the AER decision on the Victorian electricity distribution determination 2011-2015	48 864
Meta Economics Consulting Group	Agricultural electricity consumer issues in the NEM	53 800
Alternative Technology Association	NEM Advocacy 2010-11	103 338
Consumer Action Law Centre and Consumer Utilities Advocacy Centre	Support for intervention in Tribunal proceedings on AER Victorian distribution price determination	103 800
Total		447 094
Electricity research		
Etrog Consulting	Electricity supply disconnection on change of small business tenancy	6 500
Etrog Consulting	Electricity and gas customer transfer issues for small business customers	7 800
MS Australia – Tas	Keeping Tasmania Cool Campaign	19 560
City of Victor Harbour	Demand side participation in the Fleurieu region	20 000
QCOSS	Electricity supply disconnection on change of residential tenancy	20 800
Engineroom Infrastructure Consulting	Scoping study into electricity service quality	21 000
Total Environment Centre	Consumer reactions to increased cost of electricity	28 000
QCOSS	Electricity and gas customer transfer issues	31 200
Engineroom infrastructure	Mapping retail electricity standing offer prices Australia-wide	31 500
Moreland Energy Foundation	Residential energy information portal evaluation project	38 300
Total		224 660

(Continued next page)

Table 21.2 (continued)

<i>Applicant</i>	<i>Approved project</i>	<i>\$ grant</i>
Joint electricity and gas advocacy, research and/or capacity building		
Centre for Energy and Environmental Markets University of NSW	Energy efficiency information disclosure policies for residential and commercial leased properties.	31 500
Ethnic Communities Council of NSW	Ethno-specific small business and culturally and linguistically diverse (CALD) residential energy consumer consultation report	32 600
ACOSS	National consumer roundtable on energy meeting 2010-11	37 461
Tasmanian Council of Social Service	Energy research and advocacy 2010-11	39 340
Consumer Utilities Advocacy Centre	Overcoming the information asymmetry: approaches to improving customer participation in the energy retail market	44 700
100% Renewable Community Campaign	Regional and rural Australian Energy White Paper project	62 000
Qld University of Technology Credit and Consumer Law Program	NEM advocacy 2010-11	70 390
Uniting Care Australia	Informing Uniting Care Energy Advocacy 2010-11	100 000
Kildonan UnitingCare	Indigenous community energy education and advocacy	102 102
South Australian Council of Social Service	NEM reform advocacy capacity building project – SA – 2010-11	109 080
Total Environment Centre	NEM advocacy 2010-11	127 000
ACOSS	NEM advocacy 2010-11	143 000
Major Energy Users	Global funding 2010-11	206 000
Energy Users Association of Australia	Priority projects for 2010-11	206 000
Consumer Action Law Centre	NEM Network Coordinator and Consumer Advocate 2010-11	217 226
Total		1 432 369

Source: AEMC (2011j, pp. 101–7).

Despite these mechanisms, there is widespread dissatisfaction with consumer engagement in electricity network regulation.⁶

⁶ Dissatisfaction about consumer involvement extends to public utility regulation generally. For example, in an ACCC/AER working paper, Biggar said:

The involvement of customers in most regulatory processes in Australia is relatively weak and undeveloped. Customers do not take direct responsibility for regulatory outcomes. Customers are not directly involved in approving investments or investment-tariff trade-offs, or trade-offs between tariffs and service quality. Customers are not directly involved in the design of incentives, risk-sharing arrangements, or in the design of the regulatory framework itself. There is relatively little scope for customers to enter into new, innovative or out-of-the-ordinary arrangements with regulated firms — such as special arrangements for the approval of investment, information provision arrangements, complaint-handling procedures, longer-term price paths, and so on. (2011b, p. 42)

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- Mountain (2012b), in his submission to the Senate Select Committee on Electricity Prices, observed ‘consumer disempowerment’ during regulatory processes:

Users are entitled to participate in consultations during regulatory reviews, and to make submissions on proposals and draft decisions. But in practice, participation in these processes seems to have been ineffective in delivering outcomes that serve the long term interest of consumers. The regulator and the industry it regulates seems to have become focused on each other, rather than the needs of users. (p. 20)

- The limited merits review panel noted that consumers were seen as ‘inconvenient guests’ in the merit review process (Yarrow et al. 2012b, p. 44). However, it also observed more deep-seated problems:

The bigger problem is, to put matters simply, the inadequate attention given to the long term interests of consumers, first by the NSPs [network service providers] then by the AER, and then by the ACT [Australian Competition Tribunal]. While the Panel can make recommendations to address the third leg of this chain of neglect, more effective improvements in performance are likely to come from change that starts at the beginning of the chain, with NSPs. (p. 67)

- The limited merits review panel further noted that network service providers themselves recognised weaknesses in their relationships with consumers and major energy users (Yarrow et al. 2012b, p. 45).
- In a report for the Electricity Networks Association submitted to the limited merits review panel, Fels (2012) considered the inadequacies of existing arrangements for consumer advocacy in regulatory processes in the energy sector:
 - a) The levels of funding available through the Consumer Advocacy Panel is derisory especially when compared to the resources that are required to fund participation in a complex regulatory framework;
 - b) It seems counterproductive to split limited resources across a large number of separate [consumer advocacy] organisations. ...
 - c) The focus of existing organisations on certain consumer issues (ie vulnerable end users) while clearly desirable, does not necessarily mean they are well placed to participate in economic regulation;
 - d) While there is a role for state-based advocacy, there is no apparent basis for allowing this to distract attention from developing a national capacity in the context of a national regime administered by a national regulator. (p. 80)
- A report funded by the Consumer Advocacy Panel (Renouf and Porteous 2011) identified several weakness with current consumer advocacy in energy markets, including: a lack of a national voice; insufficient coordination; insufficient research and data (such as the lack of a national research base on energy consumer issues and inadequate access to relevant data); a too narrow focus on

particular consumer groups; insufficient resources and funding; insufficient skills or access to the right technical expertise; failure by decisions makers to consult adequately; and a lack of attention given to the overall regulatory framework (pp. 46–7).

- In its recent draft Rule determination on economic regulation of network service providers, the AEMC referred to a report by Brattle on regulatory approaches in other countries and said that:

... there does not appear to be a common approach to consumer engagement, but it would appear that other regulators engage with consumers or consumer representatives more than the AER does, both on a formal and informal basis. (2012r, p. 100)

In its recent draft Rule determination on the economic regulation of network service providers, the AEMC proposed changes with respect to the regulatory determination process, which, among other things, are intended to improve consumer engagement (2012r, pp. 152ff). These changes include requiring the:

- network service provider to indicate in its proposal the extent to which it has engaged with consumer representatives and to provide an overview paper for consumers
- AER to publish an issues paper after receiving the regulatory proposal. The purpose is to assist consumer representatives to focus on the key preliminary issues on which they should engage and comment
- AER to publish a benchmarking report that informs consumers on the relative efficiencies of network service providers
- AER, when setting capital expenditure and operating expenditure allowances, to take into account the extent to which a network service provider has engaged with consumers in preparing its forecasts.

The Commission agrees with the AEMC's proposed changes, and sets out similar recommendations in chapter 8.

In addition, the Commission considers there are strong grounds for strengthening consumer engagement in electricity network regulation by introducing arrangements to eventually enable negotiated settlements between consumers and network services providers (described in chapter 8). Such arrangements — proposed by Littlechild (for example, 2011c) — involve consumers and appointed consumer representatives taking an active role in negotiating price and quality issues with providers, with the AER then approving (or otherwise) the settlements.

More effective consumer representation

The Commission also sees a need for the creation of a publicly-funded consumer body to more effectively represent the interests of consumers in NEM policy, regulatory, rule-making and merits review processes, including in negotiations with network businesses.

The case for adequate public funding of a consumer body in relation to electricity network regulation rests on the following arguments.

- It is unlikely that there would be sufficient market-based funding of a consumer body. The nature of consumer advocacy is akin to a public service or good where it is not possible to isolate the benefits to, or appropriate the costs for providing it from, individual consumers. There is therefore the potential for free-rider problems.⁷
- Electricity network services are provided by comparatively few businesses, whereas there are a significant number of individual consumers with diffuse interests. A consumer body would provide countervailing strength to that of businesses, particularly during negotiations with those businesses and during policy, regulatory, rule-making and merits review processes.
- Electricity network service regulation is complex and the NEM itself has complex arrangements. This complexity makes it unlikely that individual consumers would have the interest, expertise and resources to participate in relevant processes, including in negotiations with network businesses.⁸

An initial question is whether a publicly-funded consumer body should address electricity — or energy — issues alone.

Given there are economies of scope in considering competition policy matters across many sectors (gas, water, telecommunications, rail and energy, among others), there may be grounds for a single body with expertise encompassing economic regulation generally (and indeed, the even wider issues encompassed by consumer policy). This is the approach taken in some other countries:

- The United Kingdom had a major publicly-funded consumer group that performed this role — the National Consumer Council, which acted on behalf of consumers in many areas. That body has now been replaced with *Consumer*

⁷ This is where a person does not pay for consumer advocacy because others will benefit without being required to pay for it.

⁸ Many of these points are extensions of the general arguments for the public funding of ‘general consumer advocacy’ set out in the Commission’s 2008 report on consumer policy framework (PC 2008, p. 59).

Focus, which merged the Welsh, Scottish and National Consumer Councils with *Postwatch* and *energywatch*. Accordingly, in the United Kingdom, there has been a shift towards even greater centralisation of advocacy and expertise.

- California has an independent consumer advocate within the California Public Utilities Commission (the Division of Ratepayer Advocates) that advocates solely on behalf of investor owned utility ratepayers in negotiated settlements with utilities. It employs around 140 staff and has an annual budget of under \$US30 million and reports to the California legislature (Mountain 2012b, p. 24). The approach is described in further detail in chapter 8.

The Commission's inquiry into consumer policy (PC 2008) addressed some of these issues. It explored the advantages and disadvantages of several models of consumer representation:

- a publicly-funded single body representing consumers across many areas of the economy (not just energy)
- more diversified support to the existing array of consumer groups.

The Commission recommended a hybrid arrangement, which was not implemented by the Australian Government:

Within the broader consumer policy implementation framework agreed to by the CoAG, the Australian Government, in consultation with [the Ministerial Council on Consumer Affairs], should take the lead role in developing arrangements to provide additional public funding to:

- help support the basic operating costs of a representative national peak consumer body;
- assist the networking and policy functions of general consumer advocacy groups; and
- enable and expansion in policy-related consumer research.

Part of the latter funding component should be used to establish and support the operation of a dedicated National Consumer Policy Research Centre (NCPRC), with the remainder provided as contestable grants for research on specified consumer policy issues. An independent review of the effectiveness of the NCPRC in delivering beneficial research outcomes should be conducted after 5 years. The new funding arrangements should be subject to appropriate guidelines and governance requirements to help ensure that taxpayer support contributes to high quality advocacy and policy research in priority areas, and that the national interest is appropriately represented. (PC 2008, recommendation 11.3)

It seems unlikely that a single consumer policy research agency will gain traction, let alone one with a wider role as an active agent in the regulatory process.

However, there are clear grounds for creating a body with a narrower focus on *energy* policy and regulation alone. Such a body could develop the appropriate economic expertise required for it to be effective. This recognises that the existing consumer groups must generally operate across a vast array of consumer policy matters. There are potentially significant economies of scale in a single body focusing on energy issues. Moreover, to the extent that a body is actively involved in negotiations, it must reasonably represent energy consumers as a whole. There is no obvious existing group that fulfils that role.

The Commission notes that there is existing support for a consumer body focused on energy policy. Having identified a range of deficiencies with current consumer advocacy in the energy sector, Fels (supported by a number of network service providers) considered that it ‘would seem likely’ that the only option⁹ with ‘any credible prospect of success’ was a ‘large peak national body’, which could be formed at the expense of existing institutions (while preserving the Consumer Advocacy Panel’s functions), and which would have substantial internal expertise and the ability to secure external assistance where necessary (2012, p. 81):

The essential problem is one of scale and resourcing. ... That is not to say there is not merit in the engagement of consumer groups in their local communities, or that diverse interests cannot be represented. It merely points out that, in the limited field of economic regulation, these considerations may be trumped by the benefits of scale and centralised expertise. (2012, p. 81)

The Total Environment Centre recently noted in its submission to the Senate Select Committee on Electricity Prices that there is currently a formal process, involving the Consumer Advocacy Panel and the SCER, to create a national peak body (tentatively called Energy Consumers Australia) for consumer advocacy on energy issues (TEC 2012, p 11). The Centre noted that the funding of the new body is expected to come from existing sources, which would affect the advocacy done by existing consumer groups.

The Commission is attracted to the notion of a consumer body with adequate funding and centralised expertise in economic regulation in energy markets. This goes beyond the current focus of many consumer groups on affordability issues.¹⁰

⁹ Fels also considered two other options — a stronger national secretariat or council to coordinate the activities of the existing consumer institutions, all of which would continue to be funded by grants from the Consumer Advocacy Panel; and a small new national body, separately funded from bodies receiving grants through the Consumer Advocacy Panel.

¹⁰ Indeed, the Commission supported a similar body in its report on the Australia’s urban water sector (PC 2011c, p. 238) where it recommended that ‘there might be a formal role for a consumer representative body in supply augmentation, pricing and setting service standards’.

The key function of such a body would be to represent the interests of all energy consumers (households, businesses and major industry users) during policy, regulatory, rule-making and limited merits review processes (such as an AER regulatory determination process). The body could also act on behalf of all consumers during negotiated settlements with network businesses.

The body would require an appropriate governance structure, which would involve a board of members appointed on the basis of merit, and an advisory panel to give the board advice on the needs of the mix of consumers concerned. As for some other institutions in the NEM, the body would be financed through a small ongoing levy on market participants (effectively amounting to a consumer levy).

Its creation would not preclude the involvement of other consumer groups in regulatory and policy processes — such as in merit reviews, policies for disadvantaged consumers, and retail reform. Indeed, throughout this inquiry, the Commission has been mindful of the need for regulatory processes to be friendly rather than hostile to consumer participation. That, if achieved, should increase the options for participation by many consumer groups.

To avoid the proliferation of new institutions, the Consumer Advocacy Panel should be wound up. Accordingly, in addition to its major role as an informed and capable body with economic expertise, the new body would take over the grant-giving functions currently performed by the Panel.

DRAFT RECOMMENDATION 21.3

There should be adequate ongoing funding of a single but broadly representative consumer body with expertise in economic regulation and relevant knowledge and understanding of energy markets. This body would:

- ***represent the interests of all consumers during energy market policy formation, regulatory and rule-making processes, merit reviews, and negotiations with providers of electricity networks and gas pipelines***
- ***subsume the role of the existing Consumer Advocacy Panel into its broader functions***
- ***be funded through a levy on market participants, drawing on the approach used to currently fund the Consumer Advocacy Panel***
- ***have a governance structure that involved a board of members appointed on merit, and an advisory panel to give the board advice on the needs of the mix of customers concerned.***

The Commission notes that the limited merits review panel has reported on the role of consumers and their representatives in relevant decision making processes,

including review processes, and will be considering the issue further in its final report to SCER (Yarrow et. al. 2012a, 2012b).

21.3 Processes for amending electricity network regulation

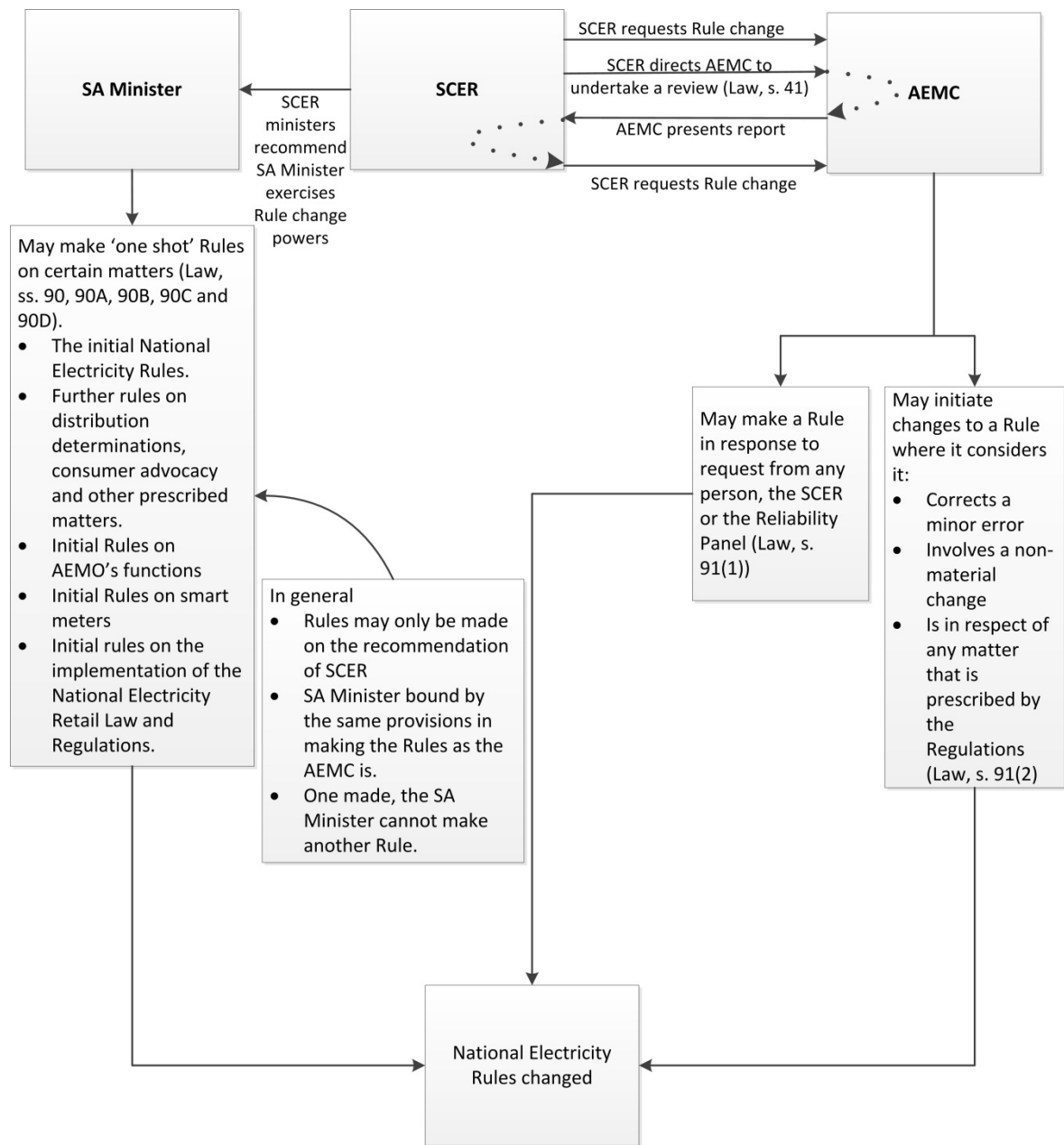
The NEM overarching policy and legal framework contains processes that enable changes to the National Electricity Law, Regulations and Rules.

The National Electricity Rules, in particular, contain much national electricity regulation. As such, its processes for change are directly relevant to the implementation of many of the Commission's recommendations in this inquiry. These processes can affect not only the quality of the changes, but the timeliness and cost of implementing them.

The SCER is responsible for developing NEM policy and does not have power of its own to change the National Electricity Rules. However, with the approval of the other energy ministers, the South Australian Minister has had, and exercised, powers to make initial Rules on certain matters (figure 21.3). Aside from the power to make the initial National Electricity Rules, it appears the Minister has exercised these powers four times. The latest use was in July 2012 in respect of the National Energy Retail Law and Regulations. However, the advice given to the Commission suggests that the capacity for making new Rules is now exhausted, so that the National Electricity Law would need to be amended to give the Minister a further capacity to act. There are precedents for this in narrow areas of policy concern, but there is no precedent or existing statutory basis for the Minister to wield broad powers.

The AEMC, as the rule maker, has responsibility for developing and amending the National Electricity Rules to achieve the NEO. It either initiates changes to the Rules that are minor, or immaterial, or prescribed in the Regulations, or it responds to requests, including from the SCER, to consider and then decide upon changes to the Rules (figure 21.3).

Figure 21.3 Pathways to changing the National Electricity Rules



Data source: National Electricity Law.

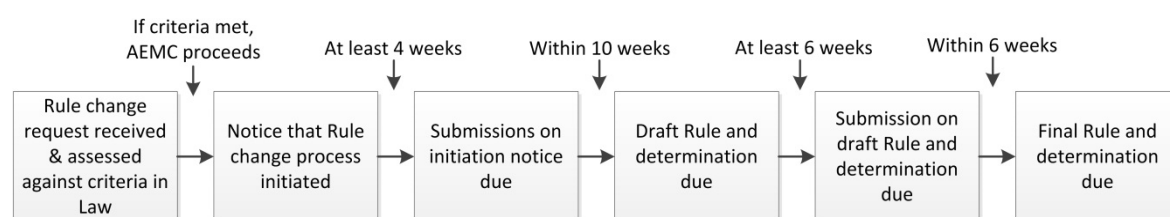
The AEMC administers three different rule making processes under the National Electricity Law:

- A standard process (figure 21.4) —involving two rounds of public consultation and a draft determination, which can be completed within 26 weeks of initiating the process (AEMC, pers. comm, 30 August 2012).
- A fast-track process for rules where: there has been adequate first round public consultation by an 'electricity market regulatory body' (such as the AER or

AEMO); or the request is based on an AEMC Rule review or a SCER-directed review (National Electricity Law, s. 96A). This process can take 21 weeks from initiating the process, but is rarely used (AEMC, pers. com, 30 August 2012 and 5 October 2012).

- An expedited process for ‘non-controversial’ or ‘urgent’ rules, involving one round of public consultation, which can be completed within six weeks of initiating the process (AEMC, pers. comm, 30 August 2012).

Figure 21.4 AEMC’s standard rule making process and timeline^a



^a This process is followed by the AEMC under the National Electricity Law, the National Gas Law and the National Energy Retail Law. In limited circumstances there may be provision for additional steps in the process — for example, the National Electricity Law provides for a public hearing before or after the draft Rule and determination.

Data sources: AEMC, pers. comm., 30 Aug 2012 and 5 Oct 2012; AEMC (2012s).

The AEMC’s rule making powers are unusual in that, unlike other national regulatory bodies such as the Food Standards Australia and New Zealand and the National Transport Commission, the AEMC is not required to have its Rules endorsed by the SCER, parliament or government.

The Rule change processes administered by the AEMC have several desirable features.

- They ensure that ministers in the SCER are focused on high-level policy in relation to the NEM, rather than on technical and detailed regulatory minutiae.
- They may avoid the inertia sometimes associated with the imperative to get ministerial agreement in COAG bodies (although the processes of the AEMC, in their own right, involve delays, sometimes of one or more years, with the exception noted below).
- They are compatible with COAG’s regulation impact analysis framework (PC 2012, figure 1.3, p. 39) and, in particular, with elements of a regulatory impact statement (box 21.4). For example, in considering a rule change request the AEMC: abides by the NEO; considers the benefits and costs of the proposed Rule change; considers whether there is a ‘more preferable’ Rule; consults with stakeholders; and issues a draft determination (AEMC 2012s).

- They allow the AEMC to fast-track or expedite the Rule change process in certain circumstances.
- They enable NEM participants, as well as the SCER and others in the community, to actively participate in initiating Rule changes.

However, it is not clear whether Rule changes proposed from reviews not already specified in the National Electricity Law can currently be fast-tracked (or expedited) by the AEMC. The Commission notes that, along with its own inquiry, there are other reviews concerning electricity network regulation — for example, the independent panel carrying out the limited merits review commissioned by the SCER. The recommendations from these reviews may require examination by the AEMC under its standard Rule change process.

Box 21.4 COAG regulation impact statements

A regulation impact statement is required for agreements or decisions of the Council of Australian Governments (COAG), Commonwealth-State Ministerial Councils and national standard setting bodies which, when implemented, would encourage or force businesses or individuals to pursue their interests in ways they would not otherwise have done.

The primary role of the regulation impact statement is to improve government decision-making processes by ensuring that all relevant information is presented to the decision makers when a decision is being made or agreement is otherwise being sought.

A regulation impact statement has seven elements, setting out:

- the problem or issues which give rise to the need for action
- the desired objective(s)
- the options (regulatory and/or non-regulatory) that may constitute viable means for achieving the desired objective(s)
- an assessment of the impact (costs, benefits and, where relevant, levels of risk) on consumers, business, government and the community of each option
- a consultation statement
- a recommended option
- a strategy to implement and review the preferred option.

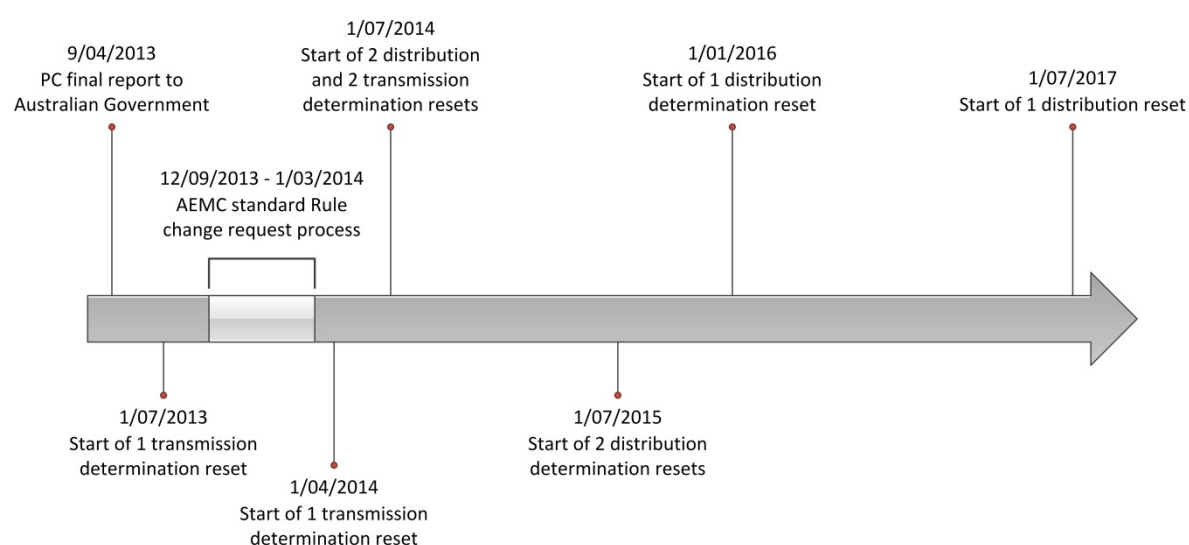
Although a COAG regulation impact statement is required in relation to changes to the National Electricity Law and Regulations, it is not explicitly required in relation to changes to the National Electricity Rules.

Source: Department of Finance (2008).

Two adverse consequences of this are that the benefits from reforms are delayed and there is an added consultation burden on stakeholders. For example, were the AEMC's standard process for Rule changes to be applied to any of the recommendations from this inquiry, that process would need to commence well

before September 2013 in order to have any possible effects on transmission and distribution regulatory determinations before they are next reset from 1 July 2013 (figure 21.5). The possible delays apparent in following this path have motivated the Commission to consider other approaches.

Figure 21.5 Timing is everything^a



^a Assumes the standard Rule change process takes around 26 weeks.

Data sources: Dates for start of revenue resets of distribution and transmission – chapter 2, table 2.5.

As an alternative, the Commission considers that the existing National Electricity Law should be amended by giving the:

- AEMC the power to fast-track Rule change requests from the SCER where they stem from recommendations from an appropriately undertaken review and where the SCER agrees the recommendations could be suitably fast-tracked
- South Australian Minister a broader power to make Rules with the agreement of the SCER.

An appropriately undertaken review would comply with the following key features:

- The reviewing institution is independent and has the necessary expertise.
- The review is consistent with COAG's regulatory impact analysis requirements — for example, the review involves public consultation, considers all the elements of a COAG regulatory impact statement (box 21.4), and makes the outcomes of the review public (preferably with a draft report as part of the process).
- The review is recent, say within the last two to three years.

-
- The review contains sufficiently suitable and detailed analysis to support a Rule change proposal.¹¹

This option would reduce: the burden on stakeholders from engaging in further unnecessary consultations; any undue delays in making Rules that have already been identified as worthwhile; and the costs of implementation. Although this option bypasses the checks and balances inherent as part of the current AEMC Rule change process, the Commission believes that the pre-conditions outlined provide an adequate alternative.

DRAFT RECOMMENDATION 21.4

The National Electricity Law should be amended to expedite the making of Rules arising from any appropriately conducted independent review relevant to the National Electricity Market and that are agreed by the Standing Council on Energy and Resources. This should be achieved by giving the:

- ***Australian Energy Market Commission the power to expedite Rule requests and***
- ***South Australian Minister a broader power to make Rules.***

¹¹ The Commission has recently considered the relevance of previous reviews in regulation making in its draft benchmarking report on regulatory impact analysis (PC 2012d, p. 140).

APPENDICES

A Conduct of the inquiry

The Commission received the terms of reference for this inquiry on 9 January 2012. Notices were then placed in the press and on its website inviting public participation. Information about the inquiry was also circulated to parties identified as likely to have an interest.

The Commission released an issues paper on 23 February to assist inquiry participants in preparing their submissions. Forty four submissions were received prior to publication of this report. A list of these submissions is provided below.

The Commission has held informal consultations with governments, regulatory bodies, peak industry groups in the electricity sector, as well as with a number of companies and individuals. A list of the meetings and informal discussions undertaken is provided below.

The Commission would like to thank all those who contributed to the study.

Table A.1 Submissions received

<i>Participant</i>	<i>Submission No</i>
ActewAGL	14
AGL Energy Limited	27
APA Group	2
Ausgrid	19
Australian Academy of Technological Sciences and Engineering (ATSE)	9
Australian Energy Market Commission	16
Australian Energy Market Operator	32, 42
Australian Energy Regulator	13
Business SA	1
City of Sydney	39
Clean Energy Council	31, 38
Consumer Action Law Centre	5
Copper Development Centre Australia Ltd	3
Credit, Commercial and Consumer Law Program (CCCL) QUT	10
Cunningham, Michael	28
Energex Limited	20
Energy Networks Association	17, 40, 43
Energy Supply Association of Australia	23
Energy Users Association of Australia	24
EnerNOC Pty Ltd	7
Ergon Energy	8
Essential Energy	30
ETAS Utilities, CitiPower and Powercor Australia	6
Grid Australia	22, 37, 44
Hydro Tasmania	41
International Power – GDF Suez Australia (IPRA)	36
Jemena Limited	21
Loy Yang Marketing Management Company	25
Major Energy Users	11
National Generators Forum	33
Pacific Economics Group	35
Public Interest Advocacy Centre	26
Queensland Treasury Corporation	12
SP AusNet	18
Total Environment Centre Inc	15
TRU Energy	4
United Energy	29
Victorian Department of Primary Industries	34

A.1 Visits and meetings

Australia

ActewAGL

Ausgrid

ACT Environment and Sustainable Development Directorate

ACT Treasury Directorate

Australian Competition and Consumer Commission

Australian Government Department of Resources, Energy and Tourism

Australian Government, The Treasury

Australian Energy Market Commission

Australian Energy Market Operator

Australian Energy Regulator

Australian Power and Gas

Basslink

CitiPower and Powercor Australia

Electranet

Energex

Energy Network Association

Energy Retailers Association of Australia

Energy Supply Association of Australia

Energy Users Association of Australia

EnerNOC

Ergon Energy

ERM Power

Essential Energy

Essential Services Commission

Essential Services Commission of South Australia

Gerard Ledwich

Grattan Institute

Grid Australia

Henry Ergas

Hydro Tasmania

Independent Pricing and Regulatory Tribunal

Jemena

John Tamblyn
Landis and Gyr
New South Wales Department of Premier and Cabinet
New South Wales Department of Resources and Energy, Trade and Investment
New South Wales Department of Treasury
Nuttal Consulting
Office of the Tasmanian Economic Regulator
Powerlink
Q Energy
Queensland Department of Employment, Economic Development and Innovation
Queensland Department of Treasury and Trade
Queensland Department of Premiers and Cabinet
SA Power Networks
South Australian Department for Manufacturing, Innovation, Trade, Resources and Energy
SP AusNet
Tasmanian Department of Infrastructure, Energy and Resources
Tasmanian Department of Treasury and Finance
TransGrid
Transend Networks
United Energy
Victorian Competition and Efficiency Commission
Victorian Department of Premier and Cabinet
Victorian Department of Primary Industries
Western Australian Department of Finance — Office of Energy
Western Australian Department of Treasury

Overseas

Federal Energy Regulatory Commission (US) — videoconference
Ofgem (UK) — videoconference
Stephen Littlechild
William Hogan

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B The hold-up problem

As discussed in chapter 3, prominent Australian economists, most notably Biggar (2011b), suggest that the conventional rationales for regulating natural monopolies are not convincing. Instead, Biggar argues that the regulation of monopolies is based on the problem that customers can be held to ransom once they have made sunk investments that use the inputs of a natural monopoly. A sunk cost is an investment that, once made, cannot easily be recovered by selling it to another party. He argues that the hold-up problem justifies amendments to the Rules and the NEL, including a new objects clause, the removal of merit review, and the greater role for regulatory discretion. He also argues that the hold-up problem explains why regulators behave as they do, such as *apparently* seeking price stability and limiting price discrimination.

Chapter 2 summarised the thrust of the Commission's concerns about this theory, this appendix explains its limitations in greater detail.

Is the theory compelling as the primary rationale for regulation?

The underlying notion that the goal of regulation is to simulate an 'ideal' long-term contract between two parties is appealing. It captures the importance of cost minimisation, provision of information between parties, adequate infrastructure investment, and avoiding excessive prices, but also the desirability of avoiding strategic behaviour by either party (such as rent-seeking and the ex post appropriation of the kind described by Biggar). It also suggests that equity concerns described earlier should not be part of the competition regulatory contract because consumer-to-consumer transfers generally would not be addressed in a contract between consumers as a collective, and a supplier. Accordingly, the broad implications of the 'contract' approach appear to mirror those resulting from maximising community welfare. That is not surprising given that the only contract that two parties with equal bargaining power would mutually agree to would be one that involved no removable inefficiencies.

The real difficulties with the above justification for competition policy emerge when it gives primacy to the 'sunk investment' problem.

There does not need to be a single meta-theory

One immediate concern is that there can be more than one rationale for regulation of natural monopolies, even if these fall under a broad umbrella of economic efficiency. Among other factors, competition regulations can be justified on the grounds of allocative inefficiency, x-inefficiency, and foreclosure risks. Sometimes, dynamic inefficiencies, such as hold-up, may also be relevant. There is (some limited) evidence of strategic behaviour of the kind that might lead to investment hold-up. For example, many Californian oil refineries were designed to process a ‘sweet’ crude oil (an oil with low sulphur content) known as ANS. In the 1990s, ANS prices began to rise. The price charged by British Petroleum to supply ANS to a refinery was higher if the refinery was designed for ANS processing, but lower if the plant could refine other oils (McAfee 2002).¹ However, the fact that hold-up may occur sometimes does not mean that it is very important.

Do small users face hold-up problems?

Electricity network businesses transact with millions of businesses and households over long periods. The typical lumpy investments for households are appliances — such as computer equipment, televisions, air conditioning, heating and refrigerators. In 2011, there were more than one million purchases of air conditioners, with a stock of more than eight million (EnergyConsult 2010, p. 17). One in four households buy a new television each year (DEWHA 2008, p. 61). The typical household will buy some electrical appliances each year. While there is a second-hand market for these goods, it is likely that some of the value is ‘sunk’ because of the transactions costs of sales and uncertainty about the quality of second-hand goods.

It is helpful to provide a concrete example of what is purported to happen under the hold-up problem, and apply it to a household. The Smiths buy a TV on the 3rd February for \$1000. Its immediate second hand value is only \$600 because second-hand markets are imperfect, so \$400 of the value of the TV is a sunk cost. In theory, a canny network business could use its market power to increase its network charges to the Smiths after their TV purchase to appropriate up to the \$400. The network business would not do this to the Jones next door because they have yet to buy a new TV, so the network business must set a new Smith-specific tariff commencing on the 4th February. Prior to their purchase, the Smiths realise that they face the risk of future appropriation. As Biggar notes, when there are many

¹ Even this is weak evidence of actual hold-up, because hold-up is not about the actual expropriation of rents, but about the adverse investment effects of its anticipation by the non-monopoly.

customers, contracts cannot be written to avoid this risk, and vertical integration is clearly not an option. Consequently, the Smiths may not buy a TV — a clearly inefficient outcome for both the Smiths (who want to watch TV) and the network business (which wants to transport power).

When put in such concrete terms, this outcome is implausible. The Smiths could be sure that an unregulated monopoly would set inefficiently high *average* prices at all times, and may not guarantee sufficiently reliable supply (the usual textbook outcomes of monopoly), but they could be equally certain that prices would not vary before and after a major appliance purchase. For that to credibly occur, the network business would need to set household-specific tariffs (and indeed for subsequent purchases of electrical appliances with varying ‘sunkness’, appliance-specific tariffs).

If transactions costs preclude carefully-constructed contracts with large numbers of consumers (as Biggar contends), they clearly preclude this kind of behaviour. Given this, the Smiths can buy appliances without concern about ex post appropriation, and the monopoly business, recognising that transactions costs preclude opportunism, will behave as the Smiths forecast. Much the same circumstances apply to hundreds of thousands of businesses. As shown in chapter 2, electricity networks are characterised by diffuse demand, accounting for a small share of the inputs of most industries.

Accordingly, simply by dint of their raw numbers, the bulk of electricity customers are not subject to the risk of ex post appropriation by an electricity network (a point also made by Boffa and Kiesling 2006). Were hold-up the *primary* motivator (as claimed) for monopoly regulation, it suggests that the ACCC/AER should not regulate these parts of the market. That would be unfortunate given the myriad of costs that monopoly power could impose on such customers. While regulators should abstain from over-regulation, the Commission considers that the ACCC and the AER have strong reasons for regulating on behalf of consumers and small businesses, and should not relinquish that role despite the absence of hold-up problems.

However, perhaps the hold-up problem applies to business customers making very large investments, but that are unable to write sufficiently complete contracts that forestall this?

Overcoming credibility problems for a monopolist selling to large business customers

A monopolist may credibly signal that it will not expropriate the sunk value of a customer's large lumpy investments in several ways.

Writing long-term contracts

While it is impossible to write perfect contracts, long-term contracts are common between large customers and businesses with market power, as demonstrated in Australian airports (PC 2011b), and in gas and electricity markets in the United States and Europe. It is notable that while Biggar cites Laffont and Tirole (2000, pp. 74–5) approvingly when they discuss the hold-up problem, he neglects their observation that:

Despite the usual difficulties involved in designing good long-term contracts, this is often a decent way to resolve the hold-up problem.

In fact, Biggar (2010) acknowledges that such long-term contracts appear to be viable in electricity:

In practice, the best we can say is that in some limited situations, long-term private contracts might be able to achieve a reasonably efficient outcome. For example, [this might occur] where the users can negotiate with potential suppliers before one or other side has sunk any investment and when the industry is stable so that reasonably long-term contracts are possible. Possible examples include ... a large electricity consumer negotiating with the electricity transmission network...²

It is also notable that large users do not cite contractual or hold-up problems as their prime concern. Rather, they are concerned about excessive costs and the deadweight losses these entail:

The NEM design is based on providing strong incentives for the supply side to provide a vibrant and responsive electricity supply. If incentives are inappropriate and over-incentivised investments are made in transmission (and distribution) networks – as have been the case under the existing Rules — users of energy will face significantly higher but arguably unnecessary costs (and hence adversely affect downstream investments). Even more importantly, the Australian economy will be incurring large dead weight losses. (Major Energy Users, sub. 11, p. 6)

² Another illustration is the long-term contracts forged in the 1980s (running to 2014) between Alcoa and the Victorian Government — effectively the supplier in this instance — for power tariffs that moved in line with global aluminium prices.

Other solutions to hold-up may also exist

Even without contracts, hold-up may not occur where the monopolist:

- vertically integrates with those customers that need to make very large and relationship-specific investments in long-lived assets (Meade and O'Connor 2009 and Michaels 2006).³ This is likely to be more feasible for this group of customers than for customers generally
- takes an equity position in the customer's business (Harbaugh 2001) or an option to do so (Nöldeke and Schmidt 1998).

Hold-up problems may also be overcome when there are many repeated transactions with a customer or where the investments occur in stages. For example, notwithstanding vague contracts, there is a stable long-run relationship between Japanese auto-component manufacturers and automakers because there are long-run gains for both parties from stable long-term trading (Hölmstrom and Roberts 1998). Similarly, electricity users will often expand or upgrade plants over time, with the additional power usage providing a revenue source for the networks. The monopolist can reveal that it is acting in good faith by not behaving opportunistically for each of the successive customer investments. As in the auto case, any single incident of hold-up would end that relationship. The authors note:

The familiar logic of repeated games, that future rewards and punishments motivate current behaviour, supports the on-going dealings. An attempted hold-up would presumably bring severe future penalties. (Hölmstrom and Roberts 1998, p. 82)

Other (theoretically based) papers support the view that repeated transactions resolve hold-up.⁴ But such is the fragility of results to alternative assumptions, that others find quite the opposite conclusion, or supply other reasons why hold-up might or might not occur. This reflects another fundamental problem in the practical policy application of hold-up ideas. The hold-up literature is a lively part of the burgeoning field of industrial organisation and game theory, driven by elegance and assumption. The overwhelming bulk of papers are theoretical and, to the extent that there are empirical papers, they often rely on experiments involving students (for example, Hoppe and Schmitz 2011). It is hard to be confident that a single interpretation of hold-up within this vast and chaotic literature provides a credible basis for price regulation by competition authorities.

³ Notably, in this literature, the hold-up problems are more realistic, relating mainly to the relationships between generators and transmission businesses, not between transmission businesses and downstream customers.

⁴ As explored in various contexts by Pitchford and Synder (2004); De Fraja (1999); Che (2000); Che and Sákovic (2004); and Iyer and Schoar (2009).

It is also not clear why the problem of hold-up is unique to a natural monopoly's dealings with its customers. Most of the examples of potential hold-up and the way it is resolved occur in industries where (ex ante) no market power is obvious.

Would price regulation be the remedy for hold-up?

It is also not clear that even were a dominant business to ex post exploit a customer making sunk investments that the solution would be price regulation. Some possible targeted alternatives would be:

- ex post action based on common law breaches of the duty of good faith and fair dealing (Shavell 2007)
- specific competition laws (resembling Article 82 in the European Union Competition Law⁵)
- ex ante oversight of particular long-term contracts that risked anti-competitive outcomes.

In US and European law it is unlikely that a business with monopoly power could confiscate the investment returns of purchasers through re-negotiation of a contract, although it might reduce their profits (White 2012). Even if there are transactions costs in taking action of these kinds, the threat of litigation may deter opportunistic behaviour. So were hold-up the primary problem posed by monopoly, then that might suggest the redundancy of price regulation — a problematic policy position. A conventional model of monopoly would not reach that conclusion.

It is notable that where international competition authorities query contracts, it is not because of their potential to create hold-up but because of risks of foreclosure and concerns about average pricing levels, such as cases:

- where a party with market power seeks to tie up its purchasers in long-term supply contracts, so that parties competing with the dominant firm cannot supply its customers (Bellantuono 2008, Bessot et al. 2011). For example, a major gas supplier in Europe attempted to tie up many generators in long-term contracts
- where, ex ante, parties sign long-term contracts with 'eyes wide open', but that the purchaser *without* market power wishes to void at a later time advantageous to itself. For instance, utilities made long-term energy contracts with generators during the Californian electricity crisis to protect themselves from high spot

⁵ Article 82 requires that any abuse by one or more undertakings of a dominant position shall be prohibited as incompatible with the common market in so far as it may affect trade between member states. Among other things, such abuse may consist of directly or indirectly imposing unfair purchase or selling prices or other unfair trading conditions.

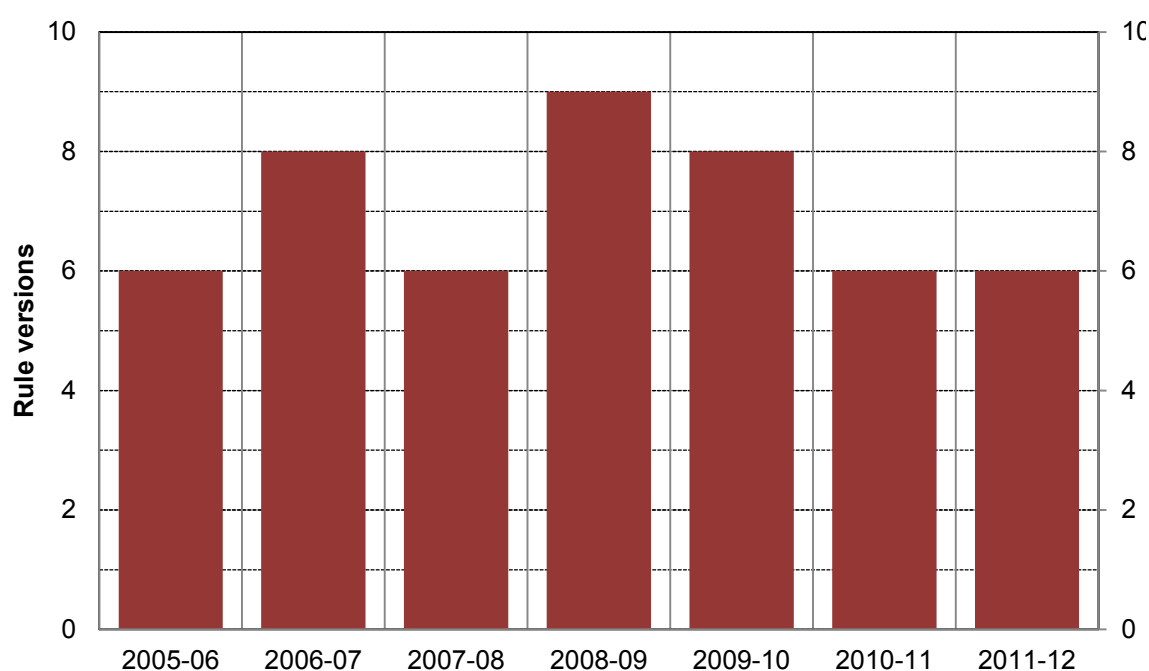
prices, and then subsequently sought to have these contracts voided. This is a complex area in law, with considerable debate about the circumstances where a court may (or should) void a contract, but does not resemble the hold-up of Biggar's kind.

Are regulations a superior form of implicit contract?

Regardless, the notion that regulations (and their underpinning laws) create credible long-term contracts belies how regulations change and how regulators behave.

The asset life of electricity transmission equipment is often 40 to 50 years, and some Australian networks have operating equipment up to 80 years old (Crisp 2003, p. 22). Similarly, customers' investments can be in long-lived assets whose returns are dependent on efficiently supplied and priced network services (such as a smelter, glass works or manufacturing plant). Yet from 2005-06 to 2011-12, there have been 49 versions of the National Electricity Rules (and two more versions in 2012-13 so far). There is no sign that the numbers of new versions per year are trending down (figure B.1).

Figure B.1 There have been 49 versions of the 'Rules' from 2005-06 to 2011-12



Data source: Information obtained from the AEMC website.

Were this to continue for an asset with a life of 40 years (whether owned by the customer or the monopolist), the economic value of the asset would be exposed to nearly 280 sets of possible new regulatory influences during its life. While most of these influences would probably be benign, there is no contract to ensure that. In effect, governments (and regulators through their discretion) can re-negotiate the implicit contract between network businesses and their customers. Neither party would know what the terms would look like five years later. Accordingly, both parties are exposed to regulatory hold-up.

The risks are likely to be greater for the network businesses. While some customers of electricity networks make large lumpy investments that is not true for most of them. In comparison, *all* network businesses are highly capital intensive and have very long-lived, relationship specific assets (chapter 2). Indeed, some prominent competition economists consider that one of the major risks in competition regulation arise because regulators are unable to commit that they will not expropriate the returns from the monopolist's long-lived sunk assets (Vogelsang 2010, Panzar 2012, Knittel 2006).

Unlike commercial arrangements, a regulator has an unassailable power to expropriate the monopolist's sunk investment unless moderated by some kind of merit appeal process. In effect, a regulator may possess monopoly powers well in excess of the business they regulate. As noted above, Biggar proposes considerable regulatory discretion, no merit review process and that (reversing the current onus of proof in the existing Rules) the business should prove that the regulator is wrong in any determination (2011b, p. 8). These elements undermine the credibility of the regulator to create long-term implicit contracts immune from regulatory hold-up.

Do regulators ignore deadweight costs in practice?

Biggar (2011b, p. 23) asserts that:

... regulators do not, in practice, behave as though minimising deadweight loss is their primary concern (or virtually any concern at all).

There are two problems with this contention.

Regulatory practice is not a guide to good regulation

The massive literature on regulatory capture contradicts the notion that regulatory behaviour necessarily reveals the legitimate rationale for regulation.⁶ As an illustration, in the early 20th century United States, corruption among municipal energy regulators was apparently rife (Troeskin 2006). More recently, the distinguished UK competition economist, George Yarrow (2011a) quipped:

On the basis of observed behaviours, the likely conclusion of a visiting social scien[tist] could well be that ‘the principal objective of regulators is to convey a good impression of themselves’.

Nevertheless, it is reasonable to observe regulators’ behaviour and ask them about their motivations because, through experimentation and learning, they might have discovered a different or additional basis for regulation. However, the ultimate test is not what regulators do but whether, given market behaviour and its outcomes, regulation is justified on welfare grounds.

Mostly Australian regulators do not say that hold-up is their principal concern

In any case, Australian regulators often affirm the relevance of deadweight costs and generally behave in a way consistent with this:

- The ACCC Deputy CEO of Regulatory Affairs, Mark Pearson (2011) has recently affirmed the latter ‘text book’ view, noting that the fundamental problem of market power is a ‘contraction in supply resulting in higher prices or poorer quality of service.’
- While sometimes regulators may question particular tariff structures, it is not clear that they always oppose price discrimination. Two-part tariff schemes (second-degree price discrimination) are common in infrastructure access arrangements in Australia and internationally, and are seen as economically efficient (a point made by Biggar (2001)). The AER has not argued for limiting the considerable discretion of electricity distribution businesses to set prices flexibly (AER 2012a, p. 17) and the Rules specify the need for efficient tariff structures (clause 6.2.5(c)).
- The AER does not oppose peak load pricing and were they to do so, it would be undesirable for consumers as a whole (chapters 9–12). A major barrier to peak load pricing in electricity has been the absence of smart meters, a technological barrier, rather than an intrinsic hostility by regulators. Peak load pricing is common among commercial customers, as is pre-agreed load shedding by large

⁶ For example, as described by Levi-Faur (2012), Baldwin et al. (2011); Boehm (2007); Levine and Forrence (1990) and Stigler (1971).

customers when total electricity demand exceeds the available supply. The AER has not expressed opposition to critical peak pricing trials as part of demand management trials (AER 2012b, p. 16).

- Even were it to occur, the reason that hold-up is problematic is that it curtails investment, with the dynamic inefficiencies that flow from that. As pointed out by Frontier Economics (2011, p. 22), this is just one form of a deadweight loss.

A recent ACCC working paper (ACCC 2012) has also highlighted the primacy of the standard efficiency criteria for regulation of infrastructure:

Across the OECD countries, it is common for governments to operate regulatory regimes aimed at producing more efficient outcomes than the unrestrained market. In Australia, as in most OECD countries, efficiency is interpreted broadly to include ... cost efficiency... allocative efficiency... and dynamic efficiency These efficiency criteria underlie both the National Electricity Law (NEL) and the National Gas Law (NGL). They date back to the Hilmer reforms of the early nineties... and pervade all of Australia's infrastructure regulation.

C Hedging in the electricity market

C.1 The role of hedging

Electricity prices in the spot market are highly variable. The price, which usually sits between \$0 and \$100 per megawatt hour, can suddenly rise to \$12 900 or fall to -\$1000 per megawatt hour, depending on market conditions.

Such price fluctuations potentially expose both retailers and generators to significant risk. Retailers make agreements with homes and businesses to deliver electricity at an agreed price — agreements that must be met even if the price in the spot market rises dramatically.

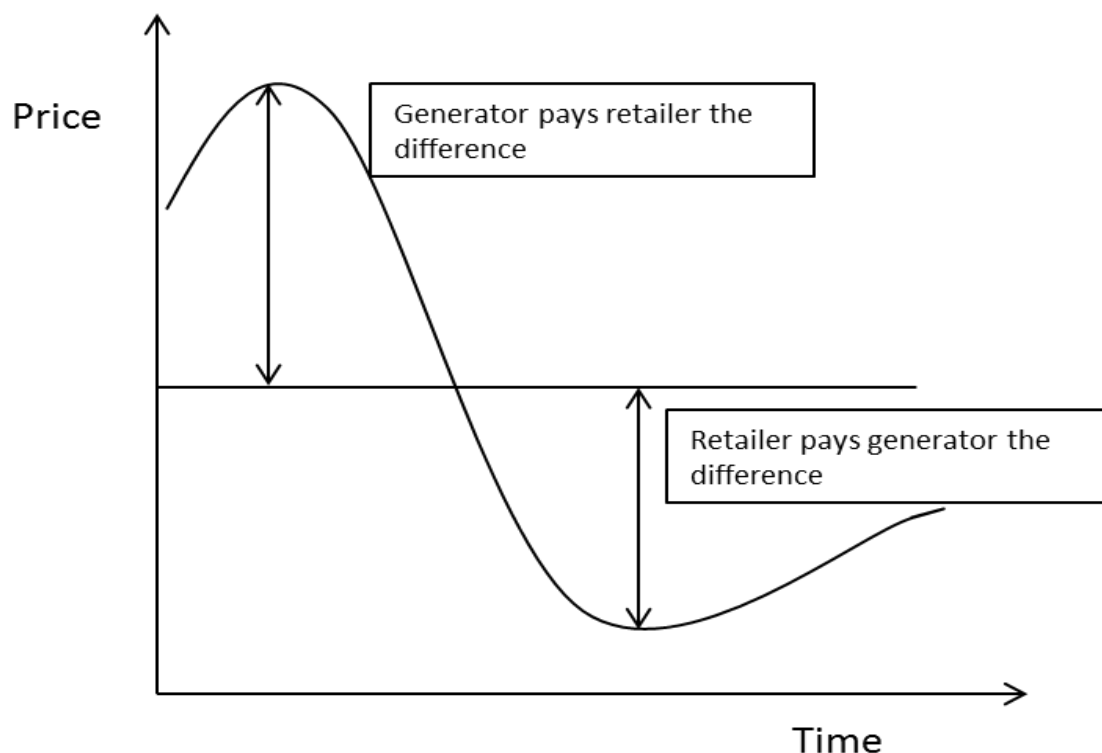
Likewise, the volatile nature of electricity prices means that a large proportion of generator returns in the spot market come from a relatively small number of events.¹ Were a generator to try to deal directly with the spot market, and these events did not eventuate (for example there may be a series of mild summers) the generator may not receive an adequate return on its investment.

In practice, often neither party has to bear the risk described above. This is because a high price event that is a ‘bad’ outcome for a retailer also happens to be a ‘good’ outcome for a generator. These two parties can agree to a hedging contract that will effectively set the price in advance (box C.1).

¹ For example, the submission from the Energy Users Association of Australia (sub. 24, p. 13) provides an example from South Australia where the 72 highest half-hourly price intervals accounted for 50 per cent, 44 per cent and 26 per cent of the annual revenue in the spot market between 2008, 2009 and 2010, respectively.

Box C.1 A basic hedging contract

It is not possible for parties to trade in electricity directly because in the National Electricity Market (NEM), all electricity must be bought and sold through the central pool. However, it is possible for generators and retailers to agree to a contract that effectively delivers the same outcome. That is, if the spot price is 'high', the generator agrees to pay the retailer; and if the spot price is 'low', the retailer agrees to pay the generator.



This type of contract allows a retailer and a generator to deal in advance for a given quantity of electricity. However, in practice, neither the retailer nor the generator will typically know how much electricity they need to trade. Managing this quantity risk requires a variety of different hedging products. However, they are all based on the premise of managing exposure to the price risk in the spot market.

C.2 Types of hedging product

A range of products exist to allow retailers and generators to trade electricity in quantities that vary throughout the day and that are unpredictable. The basic products available are:

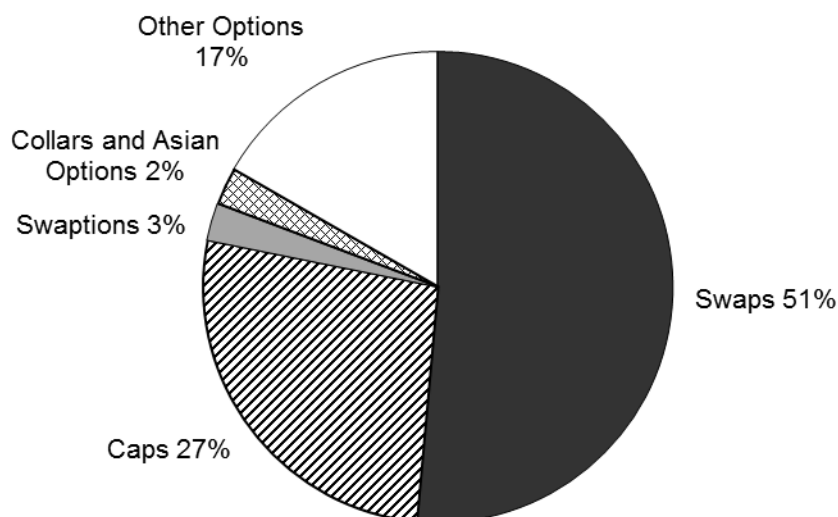
- *A base load swap* — a contract to trade a fixed amount of electricity for a certain price at all times in a day.
- *A peaking swap* — similar to a base load swap, but applying to trade only during a specific time of the day — for example from 7am to 10pm — and only on working days.
- *A flat cap* — a contract that gives the holder the option to buy a given amount of electricity at an agreed price. These are often set at a strike price of \$300 in the NEM.
- *A peaking cap* — similar to a flat cap, but can only be called on during peak hours.

There are also a wide range of exotic contracts that are used by parties to manage risk, including:

- *Weather contingent options*: that can only be used if a particular weather outcome occurs, such as above average temperatures over a given period.
- *Asian options*: an option contract that can be called on if the average price of electricity is high over a predetermined period.
- *Swaptions*: an option contract that gives the holder the right to enter into a swap contract, if they choose to do so.
- *Outage protection contracts*: a product that allows generators to protect themselves against the risk of being unable to sell electricity in the spot market.
- *Load following contracts* a hedging product that follows the usage of the electricity consumer.
- *Price Floors*: a contract that gives the holder the option to sell a given amount of electricity at an agreed price.
- *Collar contracts*: A combination of a cap and floor contract that limits both upwards and downwards price movement.

The relative usage of different types of contracts is shown in figure C.1.

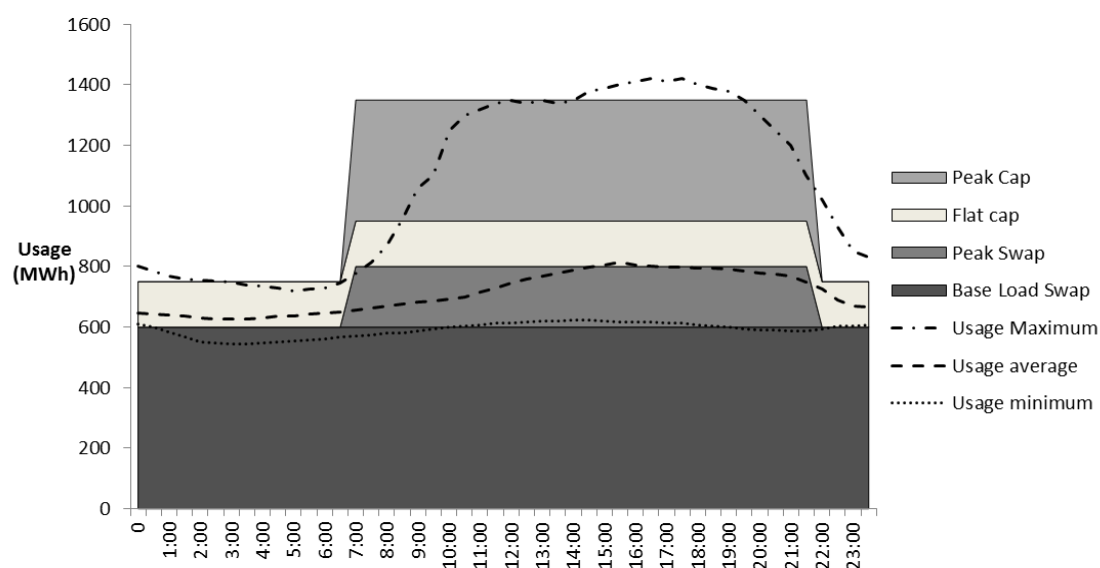
Figure C.1 **Types of contracts traded**



Data source: Australian Financial Markets Report, AFMA (2011b).

A retailer will seek to manage the risk associated with their customer load using a variety of these products. A hypothetical example for a typical day is shown in figure C.2 below. In the figure, the dotted lines represent the range electricity demand from final customers that the retailer must provide and the shaded areas represent the coverage provided by different hedging instruments.

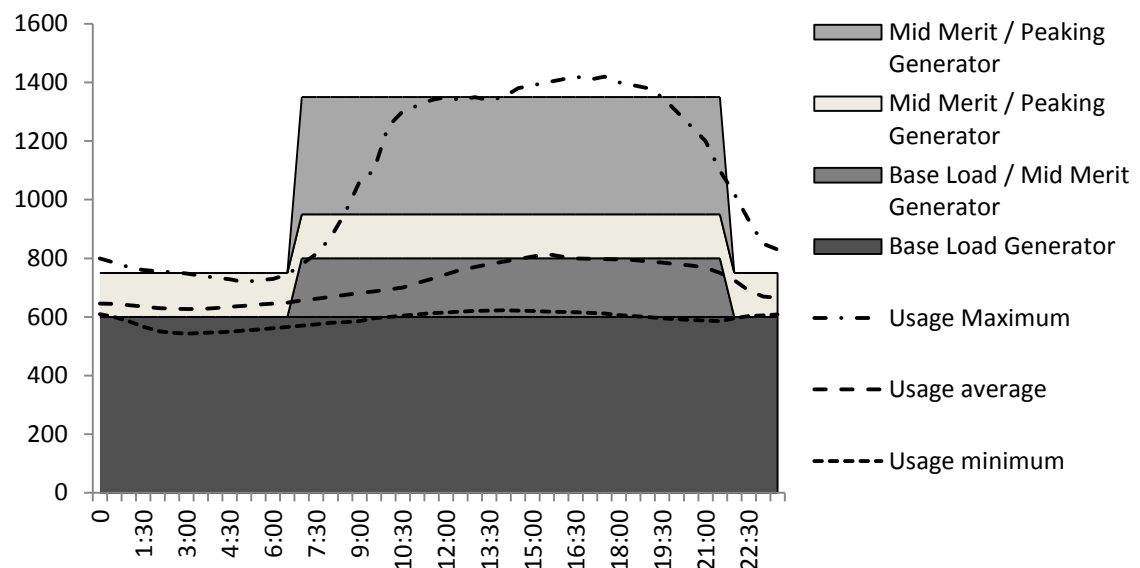
Figure C.2 **Illustrative risk management approach**



Underlying data are hypothetical and are for illustrative purposes only.

An important feature of the market is that different hedging products will be sold by different generators (figure C.3). The type of contract sold by a generator will be determined by the expected electricity output of the generator. For example, a base load generator will expect to be operating at a consistent level throughout the day, and can sell this output through a base load swap. On the other hand, a peaking generator is unlikely to be dispatched during normal market conditions when the spot market price is low, but will be dispatched when the prices are high. This makes them ideally suited to selling cap products.

Figure C.3 Illustrative range of hedging products offered by generators



Underlying data are hypothetical and are for illustrative purposes only.

C.3 Trading positions of market players

Trading positions of market players are often more complicated than the simple representations above and are commercially sensitive. As a result, it is difficult to know what a ‘typical’ trading strategy of a market participant would look like. However, discussions with participants have revealed a few ‘rules of thumb’ that can be helpful when considering trading positions.

Typically, generators will hedge all but one of the total number of generating units in the portfolio. This allows them to generate enough power to cover the contract even if one generating unit went offline or was otherwise constrained.

Retailers on the other hand, appear to have followed a number of different strategies, ranging from attempting to fully hedge their position, to holding a minimal hedging position.

The hedging market also has a large number of speculators that are not directly involved in generating or retailing electricity. Speculators will enter the market if they think that the electricity derivatives are mispriced. While commercially motivated, speculation provides liquidity to the market and thereby provides market participants greater surety that they will be able to trade in the future.

C.4 How are hedges traded?

There are three ways that hedges are traded in the NEM; Over the Counter (OTC) contracts, trading through the Sydney Futures Exchange (SFE) and through the use of the gentailer business model.

- **Over the Counter (OTC)** contracts are a direct agreement between two parties and as such allow a high level of flexibility in the terms of the arrangement. These instruments are often for a time several years in the future, meaning that each party bears some risk that the counterparty will become insolvent before the contract becomes due (credit default risk). As a result, traders will often choose only to enter into a contract with a party that has an acceptably high credit rating.
- **The Sydney Futures Exchange (SFE)** is a common exchange where participants trade in a number of standardised futures products. Trade is anonymous and risk is managed through a mark-to-market process.² As a result, there is very little credit default risk involved and lower barriers to entry to this form of trading.
- **Gentailers** are a form of natural hedge as the company involved holds both generation and retailing assets. As a result, both sides of the hedging position are held within the same company. Trading in this way allows a company to limit its exposure to the futures market, and has grown substantially in recent years.

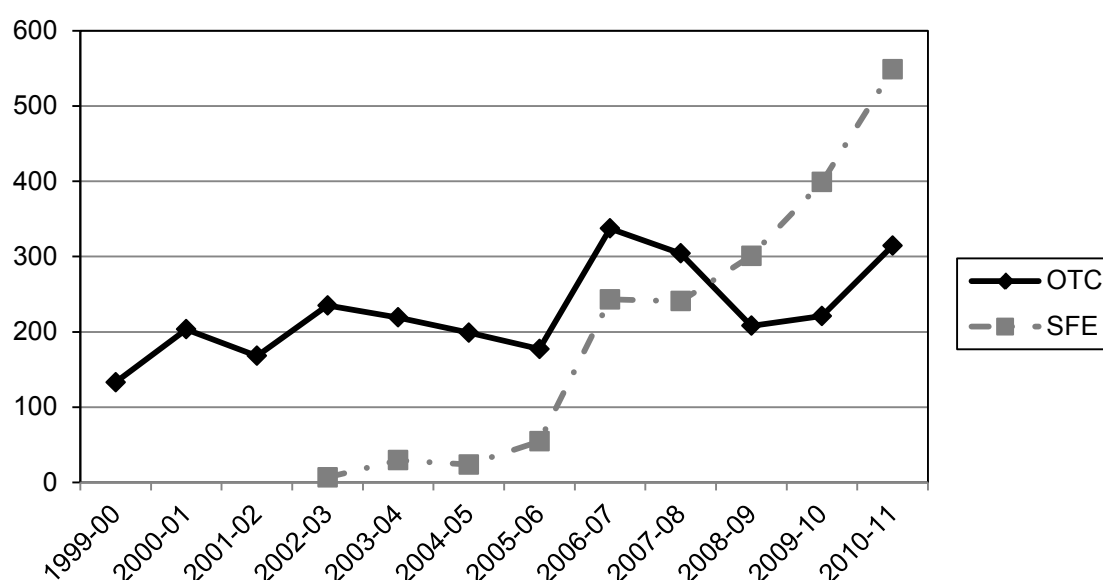
C.5 Trends in the hedging market

In 2010-11, total turnover in the OTC market was 315 million megawatt hours, with 549 million megawatt hours in the SFE market. Together these market trade contracts amounted to four and a half times as much energy as is produced in the

² The mark to market process involves payments at the end of each day to 'settle' the change in value of the option over that day.

NEM (AFMA 2011b).³ Moreover, these trading volumes have been increasing (figure C.4).

Figure C.4 Long term increase in trading volumes
(Million megawatt hours)



Data source: AFMA (2011b)

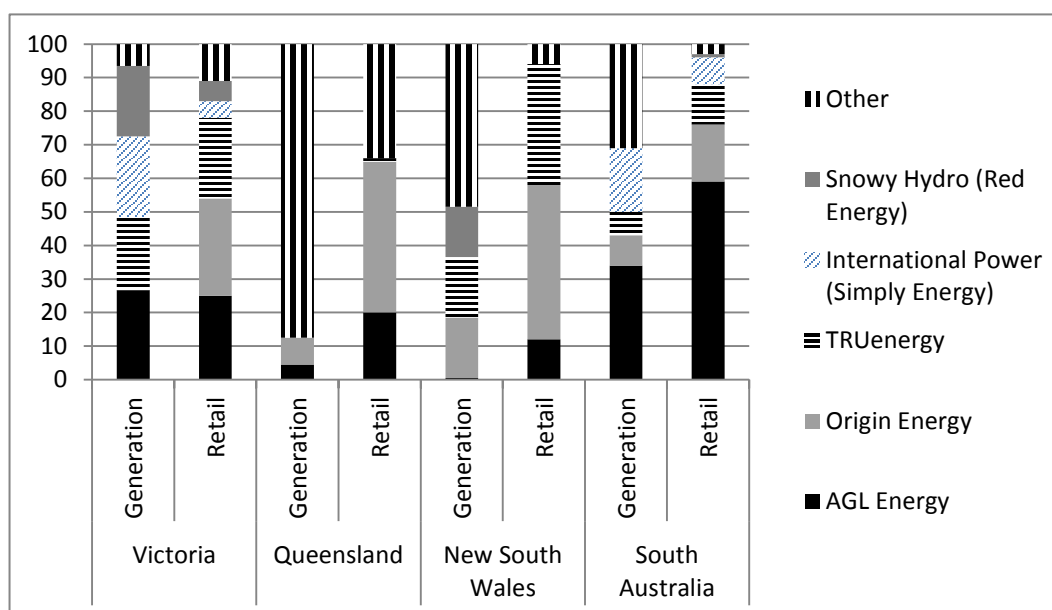
The growth has occurred in spite of a market trend towards vertical integration of generators and retailers, which tend to decrease the volume of traded derivatives as hedging is done within an organisation. The 2011 state of the energy market report (AER 2011b, p. 106) found:

Around 58 per cent of new generation capacity commissioned or committed since 2007 is controlled by Origin Energy, AGL Energy and TRUenergy. Generation investment since 2007 by entities that do not also retail energy has been negligible. In addition, many new entrant retailers in this time are vertically integrated with entities that were previously stand-alone generators — for example, International Power (trading as Simply Energy in retail markets), Infratil (Lumo Energy) and Alinta Energy.

This has led to large market positions held by a small number of prominent gentailers (figure C.5).

³ Markets where the derivative market is larger than the realised market are quite common. For example the liquidity ratio, which is the ratio of turnover on the financial market to turnover on the product market, on Australian Commonwealth Government bonds is 4.3 (AFMA 2011b).

Figure C.5 Gentailing in the NEM

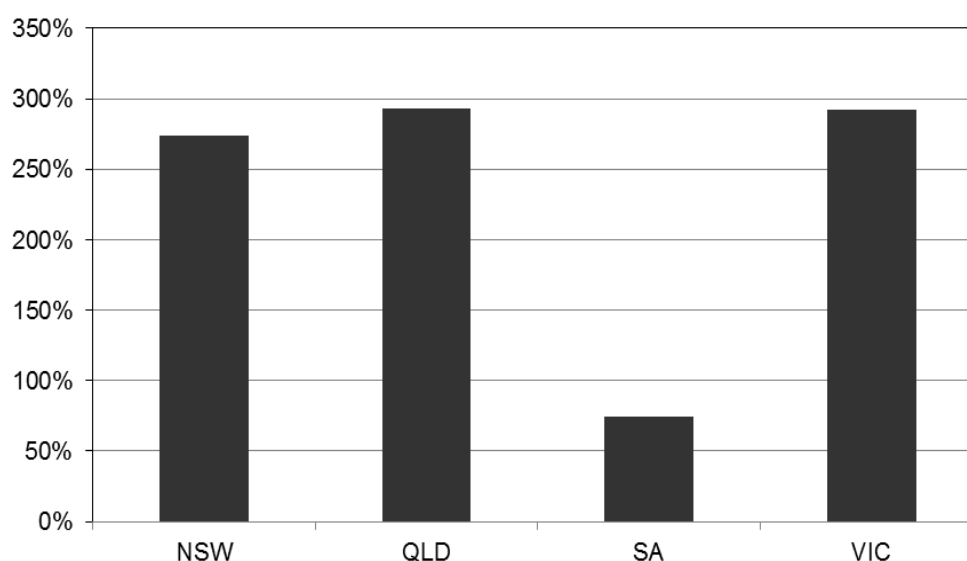


a. Generation data includes power produced under contract

Data source: 2011 State of the energy market (AER 2011b)

A high level of vertical integration is seemingly one of the reasons why the South Australian market has a lower trading level than other regions of the NEM (figure C.6). A lack of liquidity can be problematic for a derivative market. This issue, as well as a number of potential solutions are discussed in chapter 17 of this report.

Figure C.6 Liquidity ratios in different regions of the NEM



Data source: AFMA Australian Financial Markets Report (2011b), AEMO (2012).

D Modelling indirect effects in the RIT-T

Box D.1 Key Points

- The Regulatory Investment Test for Transmission (RIT-T) is a cost benefit process that is applied to all major, new transmission projects. By choosing projects that deliver the greatest net benefit for the community, the RIT-T aims to replicate the investment decisions that would be made in a competitive market environment.
- At present, this process is confined to looking at costs and benefits that occur within the electricity sector. However, it is likely that some projects, particularly interconnectors, will have impacts that are felt in areas beyond the electricity sector.
- Some have suggested that including benefits and costs from secondary markets may improve the RIT-T process. However, while it would be possible to do so, a number of potential problems would arise.
 - Other industries do not have the ability to capture indirect effects through investment decisions, meaning that an attempt to encapsulate such effects within the RIT-T process might result in overinvestment in the transmission industry.
 - To correctly measure impacts in secondary markets would require judgments to be made about the relevance of distortions across the economy for particular investment projects.
 - A cost benefit analysis that considers impacts in secondary markets should consider all projects and policies in those markets as potential options. This would greatly expand the task of the RIT-T.
- As well as the theoretical objections, there are a number of practical issues related to the modelling of indirect effects. These include choosing the correct modelling methodology and the extra cost that such modelling would involve.
- Seeking to encompass indirect impacts in the RIT-T would therefore be problematic, both on theoretical and pragmatic grounds.

The RIT-T is a cost benefit analysis that must be completed for any new transmission project (including interconnectors) costing above a threshold of \$5 million. In Victoria, the RIT-T is performed by the Australian Energy Market Operator (AEMO). In all other jurisdictions in the NEM, the test is performed by

the Transmission Network Service Provider (TNSP) that is also responsible for constructing the project suggested by the test.

As discussed in chapter 18, the aim of the RIT-T is to identify transmission investments (or any more efficient non-network options) that provide the greatest benefit to the community as measured by the sum of consumer and producer surplus. In effect, the test attempts to identify the investments that would be made were transmission projects delivered by an efficient and competitive industry.

Within the current RIT-T framework, only costs and benefits that fall on those within the electricity market can be considered. The RIT-T states that a market benefit is:

a benefit to those who consume, produce and transport electricity in the *market*, that is, the change in producer plus consumer surplus. (AER 2011, p. 4)

There has been some concern raised that constraining the RIT-T in this way may miss some important indirect or general equilibrium effects (AEMO 2011, Grid Australia sub. 22, p. 14). This appendix examines these concerns with a view to assessing whether an attempt to include broader economic effects in the RIT-T would improve the investment process.

In this regard, there are a wide range of modelling techniques that claim to capture the ‘wider benefits’ of a project to society. However, several — such as multiplier analysis — have significant methodological flaws when used for this purpose. A summary of the issues involved is provided by Denniss (2012) and the Western Australian Department of Treasury and Finance (2002).

If the RIT-T were expanded to include indirect effects, it would therefore be essential that this was done in a way that avoided such flaws. The design of the model would need to be sound, such as adapting an existing, respected model, with that model applied in a structured and consistent way. But even then, as the following discussion illustrates, there would be a range of other obstacles to overcome.

D.1 The nature of indirect effects

When a large transmission project is developed, the majority of costs and benefits are directly borne by those in the electricity market. For example, a new interconnector that runs between two regions:

- will lead to lower customer prices in the importing region as lower-cost generators in the source region are dispatched ahead of higher cost generators in

the importing region. Prices in the exporting sector would tend to be higher, leading to closer alignment of regional prices

- may improve the security and reliability of the electricity network. As an example, the Basslink interconnector provided Tasmania with power during its drought, and Victoria with power following the recent earthquake and floods which affected the Latrobe Valley generators in Victoria
- will improve the capacity for low marginal cost renewable generators to access customers in other regions, in turn making it easier to meet the Renewable Energy Target
- may undermine market power by generators in a particular region, and help to correct the adverse effects such power might have on efficient prices and investment.

While not always easily calculable, these ‘direct’ impacts are the focus of the RIT-T in its current form. However, it is likely that there will also be effects in closely related markets. For example, a major interconnector project will affect the price of goods that are produced using electricity, such as aluminium, and in turn, the prices of goods that use aluminium. As well, there will be implications for the allocation of capital and labour to industries throughout the economy, and for the makeup of imports and exports.

Such impacts have national economic welfare implications, though it is important to be careful when attempting to measure and interpret them. In some cases, outcomes that look like welfare improvements in secondary markets will already have been encapsulated in impacts in the primary market. In others cases, impacts will just be transfers between two parties, and hence have no net welfare impact. In further instances, apparent gains should be disregarded because they stem from distortions in other markets, which would be better addressed directly.

An example

In a hypothetical world of perfectly competitive markets, and no other market distortions, such as taxes or externalities, it would be possible to measure the value of a new project just by looking at the costs and benefits in the primary market (Dinwiddy and Teal, 1996). The intuition behind this result is that in the secondary market, any benefit or cost that is observed in the secondary market will have already been accounted for by changes in prices in the primary market.

This serves to illustrate how easy it can be to double count benefits when looking at the effects of policies and projects in related markets. For example, in the

aforementioned case of a transmission investment that lowers electricity prices for the aluminium industry, it is tempting to treat the lower prices and incremental activity that ensues in the aluminium industry as an additional benefit of the reform. However, these benefits have already been considered as consumer surplus in the electricity industry.

Adding some more realistic assumptions

The above result only holds when there are no distortions present in the economy. However, when this (unrealistic) condition is not met, impacts in other markets will have welfare implications. For instance, in the case of a transmission investment that lowers the price of electricity that is discussed previously, the introduction of a tax to the aluminium industry that lowers the output in that market below the efficient level will have welfare effects that will influence investment decisions in the electricity market.

As shown in figure D.1, if the new project results in a lower cost of electricity and increases output in the aluminium market from q_0 to q_1 , this will increase the sum of consumer and producer surplus by an amount equal to the shaded area.

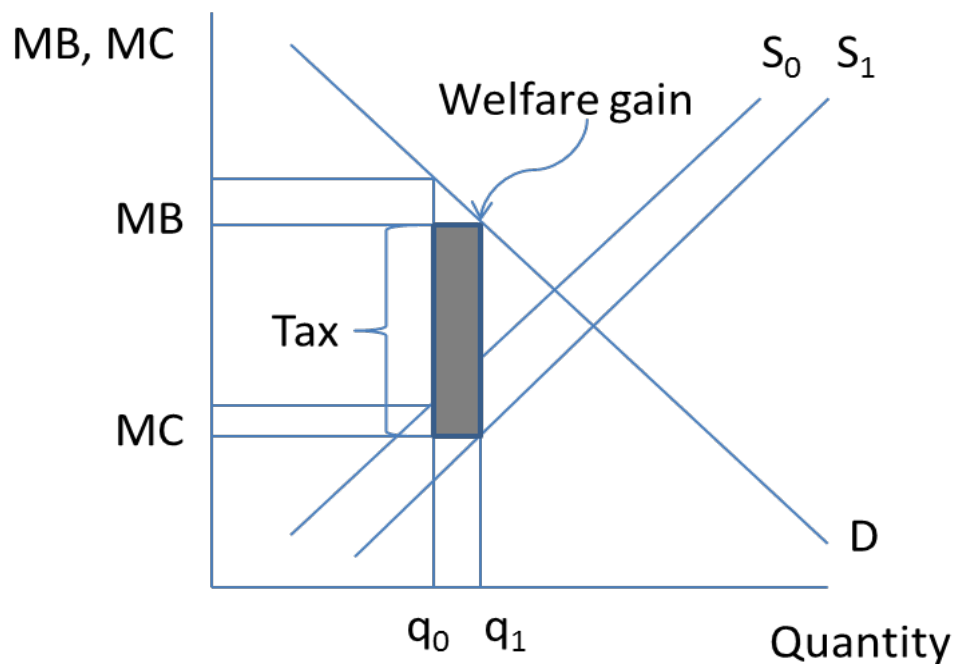
In reality, most markets in the economy have some distortion that pushes the market price away from the shadow price — which is the real resource cost of production. These distortions include:

- taxes, subsidies and any inefficient regulations
- externalities, like pollution
- non clearing markets, such as unemployment in the labour market
- the inefficient use of market power.

Importantly, these distortions do not have to occur in the markets directly affected by an investment or policy change. A distortion in one market will flow through to closely-related markets, whether they are substitutes, compliments or used as inputs in a production process. As a result, secondary impacts will have real welfare effects in most cases.

However, as the next sections explain, it is not necessarily clear such effects should be counted as a benefit in investment proposals.

Figure D.1 **Welfare effects in a distorted secondary market**

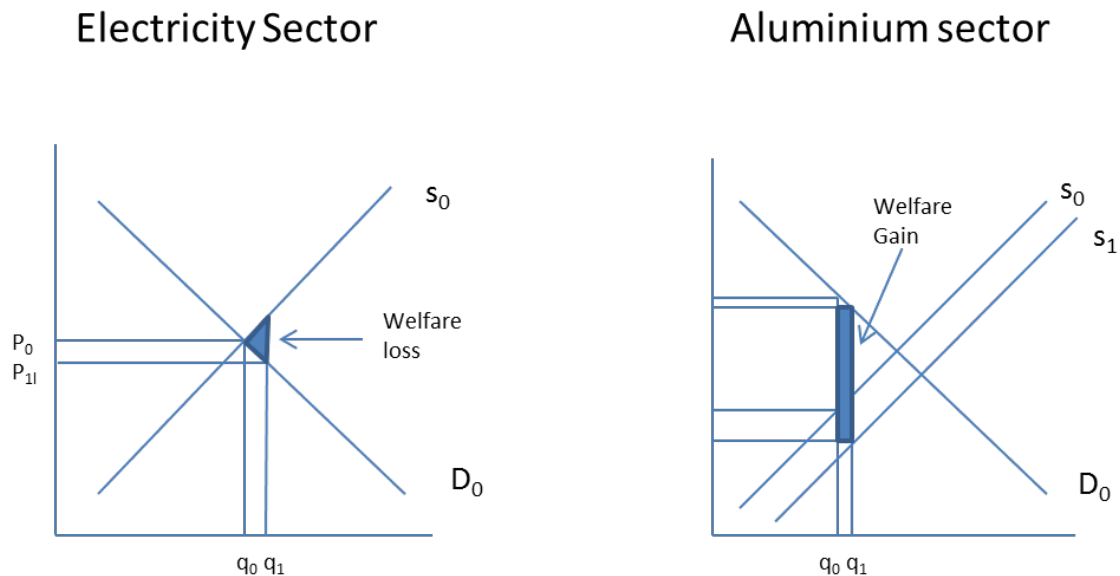


D.2 Including indirect effects in a cost benefit framework

While investments may have impacts that occur in secondary markets that are not captured by investors or consumers in the primary market, it would still be problematic for the RIT-T to attempt to incorporate such effects. Here again, the case of a transmission investment benefiting an inefficiently taxed aluminium sector is illustrative.

A RIT-T that only considered the direct costs and benefits attaching to the investment would result in q₀ of electricity being consumed at a price of p₀. However, if the benefits of offsetting the tax distortion in the aluminium market were included in the calculus, the optimal outcome would be to offer more electricity at a lower price (p₁, q₁), notwithstanding the welfare loss that would arise in the electricity sector (figure D.2).

Figure D.2 **Welfare impacts in secondary markets**



However, it is far from clear that seeking to encompass such effects in RIT-T decisions would, in practice, improve investment decision making.

- It would require the evaluation of all projects and policies in the economy simultaneously. For instance, in the example above, it may be better to address the tax in the aluminium market directly rather than through ‘second best’ investments in the transmission industry.
- Firms in other industries cannot capture benefits that occur in secondary markets, and therefore won’t consider them when making investment decisions. As such, the inclusion of indirect effects in the RIT-T may create a bias towards investment in transmission.
- In order to perform this type of assessment it would be necessary to make judgments about the magnitude of distortions in the economy, and in some cases, value judgments about the policy relevance of externalities. It is highly unlikely that a TNSP or AEMO would be best placed to make this decision.

The Commission considers that these limitations are by themselves a sufficient reason to justify limiting the costs and benefits encompassed in the RIT-T to the electricity market. However, there are also a number of practical constraints that lend further weight to this position.

D.3 Calculating indirect effects in practice

The indirect impacts of a project can be assessed using a range of analytical techniques, each of which has strengths and weaknesses.

Extending the partial equilibrium analysis

One option to assess indirect effects within the RIT-T framework would be to extend the partial equilibrium analysis to closely related sectors of the economy. This would be reasonably simple in principle, as it would extend the existing framework to look at other ‘important’ sectors, without needing to model the entire economy. Nevertheless, it would require judgment about which related markets were sufficiently important, and information about the characteristics of those markets (such as demand and supply elasticities).

Another way of extending the partial equilibrium analysis would be to employ shadow prices in the cost benefit framework. Shadow prices describe the value of a good where a market price is either not available or is a bad estimate of the true value of the good. However, as the discussion of the application of shadow prices to labour costs in box D.2 illustrates, it can be difficult to determine the ‘correct’ shadow price.

Box D.1 The shadow price of labour

The shadow price of labour is the opportunity cost of using this resource. Hence for a proposed investment in a transmission project, the shadow price would reflect what the employees involved would do if the project did not go ahead. If it is assumed that the labour market will always return to a certain level of unemployment, then new projects will not employ any additional staff at an economy wide level. In this case, the correct shadow wage would be the market wage of that worker. On the other hand, if in the absence of the project the worker would be unemployed, the shadow wage should be lower.

While there are a range of opinions on the ‘stability’ of the aggregate unemployment level, it should be noted that the Department of Finance and Deregulation (Commonwealth of Australia 2006, p. 40) recommends that unless a compelling reason can be found to suggest otherwise, it should be assumed that labour markets are fully employed. This would imply that the market wage is the appropriate shadow wage, as is currently the case in the RIT–T.

Incorporating a general equilibrium model

Another option is to use a Computable General Equilibrium (CGE) model. These models comprise a set of equations that represent a stylised version of the economy. They include a large amount of information about the tax and transfer system, as well as links between related markets. Importantly, these models are calibrated to allow for quantitative estimates of a range of changes in the economic environment to be made.

CGE models have many advantages for testing the impacts of government policies, such as tariff changes, and policies that increase productivity. However, they are less suited to modelling the impacts of individual commercial investments. Such modelling would usually require the incorporation of finer level detail which would be difficult to incorporate into the model, and would typically rely on credible assumptions rather than empirical data.

It is also unclear which welfare measure would be used in choosing between projects when using a CGE approach. While the existing RIT-T uses the sum of consumer and producer surplus to differentiate projects, CGE models usually calculate monetary measures such as Gross Domestic Product or Gross National Income.¹ While in principle CGE models could be adapted to calculate a surplus-based welfare measure, this feature is not currently available in the standard models. (Forsyth 2010, and Layman n.d)

Costs involved

All of the options discussed above will add complexity to the modelling exercise, and as a result, will increase the cost of the modelling. These costs would fall not just on the party responsible for preparing the RIT-T, but also on anyone who wants to interpret the results. As such, adoption of an extended modelling approach could have the potential to limit the involvement of interested third parties in the RIT-T process.

¹ There is a strong relationship between consumer and producer surplus and measures such as GDP and GNI. GNI is the better welfare measure of the two and has been used previously by the commission for this purpose. For a further discussion of these welfare measures see Mcloskey (1985).

How big will the effects be?

The extent to which inclusion of GE effects would alter the results of individual assessments within the RIT-T process is an empirical issue. Nevertheless, there are reasons to believe that the effects on the level of transmission and interconnection in the NEM are unlikely to be large. For most projects, there will be both indirect benefits and costs, with the net effect potentially being modest, especially relative to the primary market impacts.

D.4 In summary

On both conceptual and practical grounds, the case for including the modelling of indirect effects in the RIT-T appears to be weak. This has informed the recommendation in chapter 18 of this report that the RIT-T should not be amended to include indirect effects of investment decisions.

E International regulators' approach to merchant transmission investment

E.1 United States

Over the past decade, several merchant transmission projects have emerged in the United States, largely in response to two factors.

- The development of organised electricity markets (operated by regional transmission organisations and independent system operators). This created a need for additional transmission capacity to support generation competition, and provided opportunities for merchant transmission providers to offer competitive generation alternatives.
- State policies promoting renewable energy sources. Merchant transmission providers emerged seeking to build transmission that brought renewable energy to customers. Sources of renewable energy were typically remote from customer centres in locations with insufficient transmission capacity.

The US Federal Energy Regulatory Commission (FERC), which is responsible (among other things) for the regulation of wholesale sales of electricity and the inter-state transmission of electricity, has recognised the role merchant transmission projects play, particularly in expanding competitive generation alternatives. It distinguishes merchant transmission providers from other (incumbent) transmission providers by the fact that they ‘do not serve captive retail customers and assume all market risk of a transmission project’ (Werntz 2011, p. 424).

The FERC has developed a case by case approach, which it refined in 2009, to allowing merchant providers to charge negotiated rates with their customers on a contractual basis. The approach involves the application of a four factor test to the merchant transmission project: justness and reasonableness of rates, potential for undue discrimination, potential for undue preference including affiliate preference, and regional reliability and operational efficiency requirements. Among the requirements that FERC imposes in relation to the four factors are the following.

- The merchant provider assumes full market risk and is not building within a region to ensure there are no ‘captive customers’ to subsidise the project.

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- Merchant providers should offer all their capacity through transmission rights to all comers in ‘open season’ auctions.
 - Merchant providers are allowed to pre-subscribe a proportion of transmission capacity to ‘anchor customers’ before holding ‘open season’ auctions to allocate the remainder of their capacity.

The FERC’s approach seeks to balance the requirement of the Federal Power Act that negotiated rates are ‘just and reasonable’, core principles such as ‘open access’ to transmission and transparency in capacity allocation, and the need for merchant transmission providers to secure finance for their projects.

E.2 European Union

Until 2003, transmission investments were only permitted to be undertaken by regulated transmission and system operators (TSOs).

Prompted by concerns about under-investment in cross-border electricity transmission, and the impacts this had on competition within the European market, the European Commission (EC) introduced the second energy package in 2003 and later the third energy package in 2009.

The second energy package of 2003, allowed merchant investors to obtain authorisations to undertake merchant transmission investment (in interconnectors) from national regulatory authorities (NRAs) and the EC. To be authorised, a merchant investor had to obtain exemptions from regulated third-party access and the use of the collected congestion rent — article 7 of regulation 1228/2003 on cross border exchange.

Exemptions could only be granted if the following conditions, contained in article 7(1), were met:

- (a) the merchant interconnector should enhance competition in electricity supply
- (b) the level of the risk is such that the investment would not take place unless the exemption is granted
- (c) the interconnector must be owned by a person legally separate from the TSOs
- (d) charges must be levied on users of the interconnector

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- (e) no part of the capital or operating costs of the interconnector has been recovered from any component of charges made for the use of transmission or distribution systems linked by the interconnector
 - (f) the exemption is not to the detriment of competition or the effective functioning of the internal electricity market or the efficient functioning of the regulated systems to which the interconnector is linked.

The exemptions mainly concerned DC interconnectors, but AC interconnectors may also be considered in exceptional circumstances.

The NRAs of the member states involved generally had jurisdiction over the granting of the exemption. The merchant investor thus had to submit applications to each NRA, which could impose additional conditions. The member states or the NRAs involved had to cooperate and find common grounds for the grant of the exemption. Where there was a sustained disagreement between them, the project could not proceed. If they agreed, the EC retained the right to propose amendments or to completely withdraw the exemption.

The third energy package of 2009, with effect from March 2011, introduced a new regulation, which repealed the existing regulation on cross-border exchange. The new regulation 714/2009 retained the conditions in the previous article 7(1) for exemptions — now article 17(1) — but altered the allocation of decision making powers. NRAs remain in charge of the examination of applications but can jointly decide to delegate their power to the new Agency for the Cooperation of Energy Regulators (ACER). They are also required to notify the ACER and the EC as soon as they receive a new exemption application and inform them of their common decision. The ACER is to take a final decision in case of a sustained disagreement between the NRAs involved.