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Productivity Commission

Electricity Network Regulatory Frameworks

Productivity Commission Inquiry Report
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9 April 2013

The Hon David Bradbury MP
Assistant Treasurer
Parliament House
CANBERRA ACT 2600

Dear Assistant Treasurer

In accordance with Section 11 of the *Productivity Commission Act 1998*, we have pleasure in submitting to you the Commission's final report into Electricity Network Regulatory Frameworks.

Yours sincerely

Philip Weickhardt
Presiding Commissioner

Wendy Craik AM
Commissioner

Terms of reference

I, Wayne Swan, Deputy Prime Minister and Treasurer, pursuant to Parts 2 and 3 of the Productivity Commission Act 1998, hereby request that the Productivity Commission undertake an inquiry into electricity network frameworks, focussing on benchmarking arrangements and the effectiveness of the application by network businesses of the current regulatory regime for the evaluation and development of interregional network capacity in the National Electricity Market (NEM).

Background

Australia's electricity sector is facing a number of challenges over the coming years. This includes a large investment requirement for networks to replace ageing assets, meet growing levels of peak demand, reliability requirements and to facilitate the transition towards Australia's clean energy future.

Recent increases in network expenditure, and the resultant flow on to increases in electricity prices for end users, have highlighted the need to ensure networks continue to deliver efficient outcomes for consumers. Network regulation is a complex task requiring difficult and technical judgements. This inquiry will inform the Australian Government about whether there are any practical or empirical constraints on the use of benchmarking of network businesses and then provide advice on how benchmarking could deliver efficient outcomes, consistent with the National Electricity Objective (NEO). In addition, a second stream of this inquiry will examine if efficient levels of transmission interconnectors are being delivered, to inform the Australian Government about whether the regulatory regime is delivering efficient levels of interconnection to support the market.

Scope of the Inquiry

The Commission is requested to assess the use of benchmarking as a means of achieving the efficient delivery of network services and electricity infrastructure to meet the long term interests of consumers, consistent with the NEO. In addition, the Commission is requested to assess whether the current regulatory regime, as applied to interconnectors, is delivering efficient levels of network and generation investment across the NEM.

In undertaking the review, the Commission should:

- examine the use of benchmarking under the regulatory framework, incorporating any amendments introduced in the review period, in the National Electricity Rules and provide advice on how different benchmarking methodologies could be used to enhance efficient outcomes; and
- examine whether the regulatory regime, with respect to the delivery of interconnector investment in the NEM, is delivering economically efficient outcomes.

In undertaking the inquiry, the Commission should consider and take into account the work that is currently being progressed through the Standing Council on Energy and Resources, the Australian Energy Market Commission (AEMC) and the Australian Energy Regulator (AER). The Commission should have particular regard for the AEMC reviews into transmission frameworks, power of choice (demand side participation) and the suite of rule changes relating to network regulation currently under consideration by the AEMC in accordance with its statutory obligations.

The Commission should engage with the AEMC, the AER and the Australian Energy Market Operator in undertaking the review. In addition, the Commission should consult with Australian Government agencies, state and territory government agencies and other key stakeholders in undertaking the review.

The Commission will report within 15 months of receipt of this reference and will hold hearings for the purpose of this inquiry. The Commission is to provide both a draft and a final report, and the reports will be published. The Government will consider the Commission's recommendations, and its response will be announced as soon as possible after the receipt of the Commission's final report.

WAYNE SWAN

9 January 2012

Disclosure of interests

The *Productivity Commission Act 1998* specifies that where Commissioners have or acquire interests, pecuniary or otherwise, that could conflict with the proper performance of their functions during an inquiry they must disclose the interests.

Dr Craik has advised the Commission that she is the beneficiary of subsidised solar PV panels.

Contents

The Commission's report is in two volumes. **This volume 2 contains chapters 9 to 21, Appendix A and the References**. Volume 1 contains the Overview, the Recommendations and findings and chapters 1 to 8. Appendices B to F will only be available on the Commission's web site (http://www.pv.gov.au). Below is the table of contents for both volumes.

Volume 1

Volume 2

Acknowledgments

The Commission engaged the services of Dr John Tamblyn, a well-known expert on the National Electricity Market (who has recently been involved in two other independent reviews of aspects of the electricity industry) to review some chapters and the overview for the draft of this report. Dr Tamblyn provided valuable feedback to the Commission, for which we are most grateful. However, the views and judgements in this report are those of the Commission alone, and should not be attributed to Dr Tamblyn or any other participant, except where clearly stated.

Abbreviations and explanations

Abbreviations

AATSE	Australian Academy of Technological Sciences and Engineering
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
ASU	Australian Services Union
ATA	Australian Technology Association
CAIDI	Customer average interruption duration index
CALC	Consumer Action Law Centre
CAPEX or 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
DPI	Department of Primary Industries (Victoria)
DRED	Demand Response Enabling Device
DSP	Demand side participation
EBSS	Efficiency Benefit Sharing Scheme
ENA	Energy Networks Association
ERAA	Energy Retailers Association of Australia
esaa	Energy Supply Association of Australia
ESC	Essential Services Commission (Victoria)
ESCOSA	Essential Services Commission of South Australia
ETC	Electricity Transmission Code
EU	European Union
EUAA	Energy Users Association of Australia
FCAS	Frequency control ancillary services
GDP	Gross Domestic Product
HV	High voltage
IPART	Independent Pricing and Regulatory Tribunal (NSW)
IRSR	Inter-regional settlement residue
kV	kilovolt
kVA	kilovolt ampere
kW	kilowatt
kWh	kilowatt hour
LRIC	long-run incremental cost
LRMC	long-run marginal cost
LV	Low voltage
LYMMCo	Loy Yang Marketing Management Company
MAIFI	Momentary average interruption frequency index
MAR	Maximum annual revenue

MCE	Ministerial Council on Energy
MDMS	meter data management system
MED	Major event days
MEU	Major Energy Users
MFP	Multifactor productivity
MNSP	Market network service provider
MW	Megawatt
MVA	Megavolt amperes
MWh	Megawatt hour
NECA	National Electricity Code Administrator
NECF	National Energy 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
NGF	National Generators Forum
NGL	National Gas Law
NMS	Network management systems
NPV	Net present value
NSP	Network service provider
NTNDP	National Transmission Network Development Plan
NTP	National Transmission Planner
N-x	Measure of redundancy in network (with higher x being higher levels of redundancy)
OFA	Optional firm access
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 or opex	Operating expenditure

PC	Productivity Commission
PIAC	Public Interest Advocacy Centre
PSCR	Project Specification Consultation Report
PV	Photovoltaic
QTC	Queensland Treasury Corporation
QUT	Queensland University of Technology
RAB	Regulatory asset base
RET	Renewable Energy Target scheme
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
TEC	Total Environment Centre
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 cap

Explanations

Billion	The convention used for a billion is a thousand million (10^9).
Findings	*Findings in the body of the report are paragraphs high-lighted using italics, as this is.*
Recommendations	***Recommendations in the body of the report are high-lighted using bold italics, as this is.***

9 Peak demand and demand management

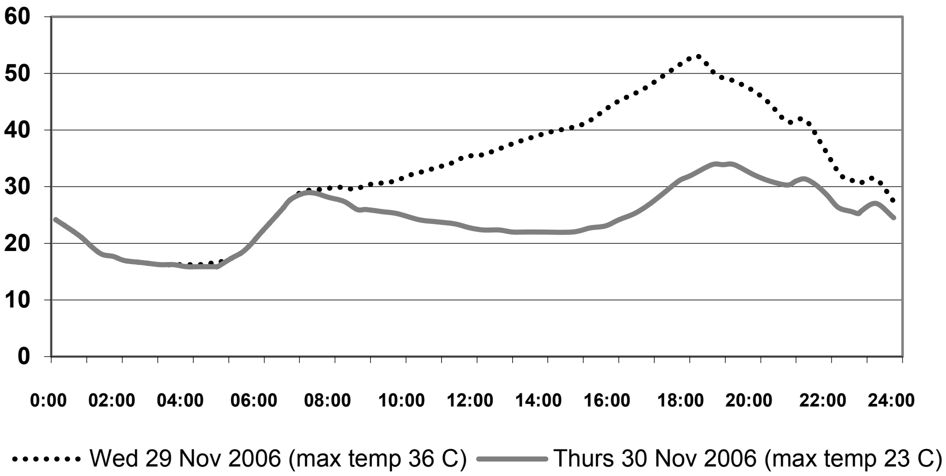
Key points

- 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. For example, in New South Wales, capacity that caters for less than 40 hours a year of electricity consumption (or less than 1 per cent of time) accounts for around 25 per cent of retail electricity bills.
- ‘Demand management’ involves using price and non-price measures to curtail customers’ use of electricity during peak demand periods, including shifting electricity usage to non-peak times.
- Most large industrial and commercial 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.
  - Currently, demand management amounts to less than 2 per cent of NEM-wide peak demand.
- Most 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 high 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 a poor understanding of potential benefits by consumers, smart meters not being widely available for residential users and distribution businesses facing conflicting incentives to pursue demand management.
- The rollout of smart meters and the adoption of critical peak pricing would reduce the required level of capacity of the network and, more broadly, lower the operating costs of managing the network. In regions with impending capacity constraints, the savings per household could be around \$100–\$200 per annum, but a rapid mandated NEM-wide rollout could readily produce net costs for Australians.

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 could even lead to a partial or full system shutdown (AEMC 2008b).

As it is currently 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.

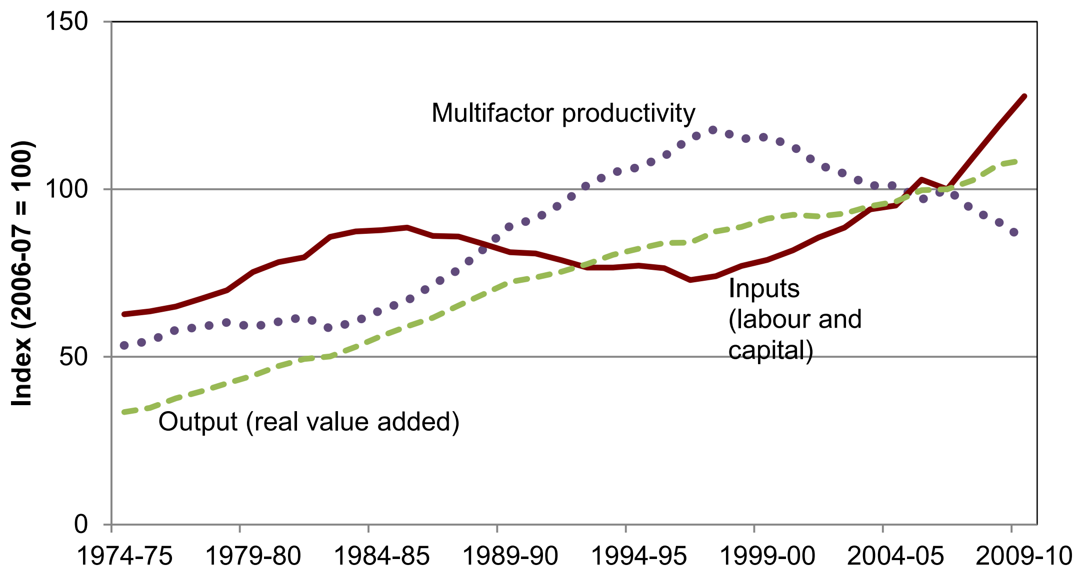
This means that infrequent and short periods of high electricity consumption can require a disproportionate share of generation and network investment, which in turn drive up the cost of electricity generally. This is the problem of 'peak' demand (or 'critical peak' demand, as the problem of major spikes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

Commentators have used different metrics to demonstrate the scale of the problem in the National Electricity Market (NEM). For example:

- around 20–30 per cent of the $60 billion of electricity network capacity in the NEM is used for less than 90 hours a year (AER 2012q, p. 15)
- capital expenditure to accommodate 'peak load growth' accounts for around 45 per cent of approved total expenditures in the distribution network, and slightly more than 50 per cent in the transmission network (AEMC 2012f)
- around 25 per cent of retail electricity bills in New South Wales reflect the cost of system capacity that is used for less than 40 hours a year (or under 1 per cent of time) (DRET 2011, p. xxii).

Although peak demand dipped slightly during the 2010-11 and 2011-12 (mild) summers, it has been trending up over the last decade.[1] To cater for this growth, there has been significant generation and network investment. Over this period, though, total demand has been flat or falling in the NEM. This has caused the utilisation of network assets to decline, contributing to a fall in multifactor productivity (figure 9.2).

Figure 9.2 **Electricity supply: inputs, output and multifactor productivity**



Data source: Topp and Kulys (2012).

1 The most common way of quantifying 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. 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 40–80 hours per year.

It is not surprising that people demand significantly more power when outside temperatures are particularly hot or cold. Consumers may well place a very high value on the comfort and amenity gained from their use of network capacity during periods of peak demand.

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

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 that consumers place on additional peak capacity.

However, as discussed below, little use is currently made of cost-reflective, time-based network pricing. Some businesses face prices that partially reflect supply costs, but this is confined mainly to wholesale energy costs[2] rather than reflecting the costs of peak network capacity. Most households and many small businesses face average (or flat) network tariffs, which means that the substantial additional costs of meeting peak demand are spread across all households and time periods. These consumers thus have little incentive to economise on their usage in peak periods, so peak consumption exceeds what would likely be observed were consumers to face prices reflecting 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 potentially 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 the 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 rules that govern how networks convert the allowed revenues from network determinations into customer charges, and in particular, whether networks should operate under a revenue cap or a weighted average price cap
- the incentives faced by network businesses to pursue demand management compared with investment in traditional network assets, and the role of the Demand Management and Embedded Generation Connection Incentive Scheme in encouraging demand management options
- the important role retail price regulation currently plays in determining the prices faced by consumers, and the feasible transition to removal of such regulation.

Scope of the analysis

The terms of reference for this inquiry focus 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 9.7).

The terms of reference for this inquiry also direct the Commission to have particular regard for the Australian Energy Market Commission's (AEMC) 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. The Commission has also taken into account the intermediary role of retailers. Effective demand management requires that cost-reflective network charges passed on to retailers are also passed on to consumers.

The Commission has given less attention to several initiatives seen as priorities by the AEMC in its final Power of Choice report (released in November 2012). For example, the AEMC has suggested changes targeting areas where there is evidence of 'low hanging fruit', including harnessing the demand management potential of industrial and large businesses users. The Commission agrees that early action in these areas would be beneficial, including the application of more efficient network charges to commercial end-users. Instead, the Commission has focused on changes that are of a longer-term nature, focused on the contribution that households make to peak demand — gradually taking effect over the medium to long term.

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

Peak demand that strains network capacity can occur in localised areas within the distribution network. It typically occurs in the late afternoon and evening on hot summer days or in the early morning on very cold days. These peaks in demand, and the network congestion that 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 network[3]).

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 within a NEM region. In such instances, energy prices in the wholesale spot market can spike and large

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.

transmission lines (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.

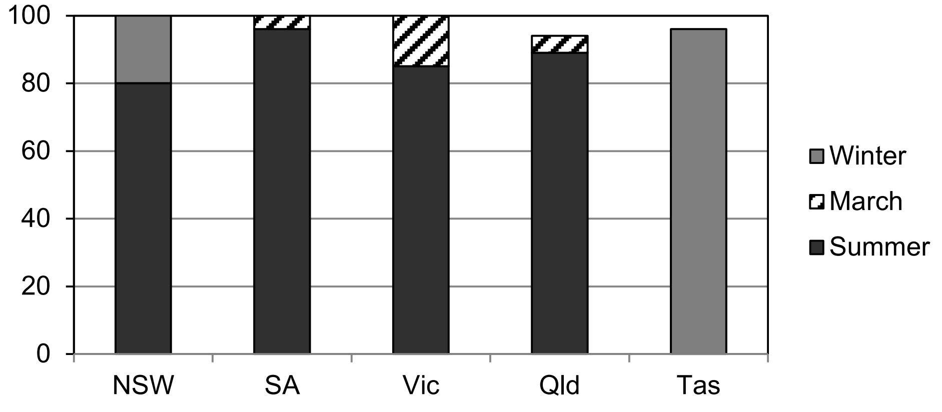
Many factors can of course contribute to wholesale price spikes. These include intra-regional transmission failures, interconnection capacity constraints, generation failures or disorderly bidding. However, as the Australian Financial Markets Association (AFMA) indicated, days with high demand are generally 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 1999–2011[a]



[a] Where the data do not add to 100, it is because the peak demand period sometimes occurs in spring.

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 peaks[4]). Even still, there may be interactions between demand management approaches designed to affect network or wholesale market peaks. As recognised by the Australian Energy Regulator (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. A threshold reduction in peak demand is required to defer a capital project and the annual deferral value — that might instead be spent on a demand management solution — varies considerably depending on inherent supply costs.[5] As the AEMC notes:

> 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]

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

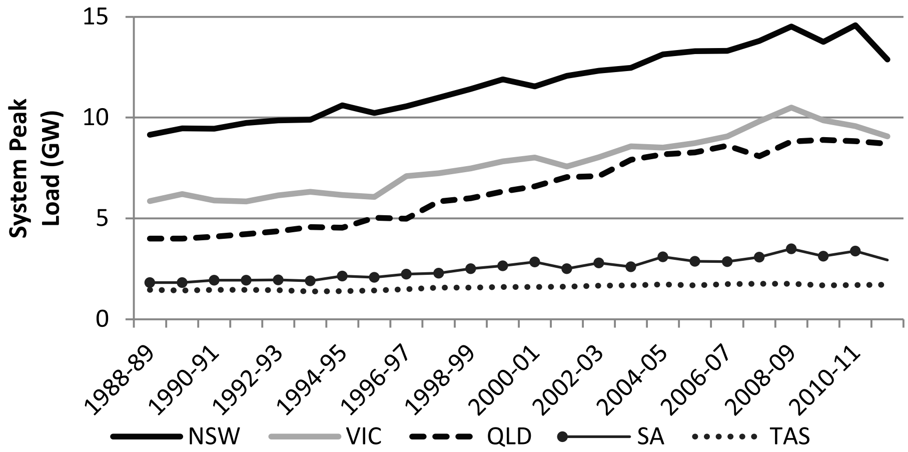
5 A large investment will have a high annual deferral value.

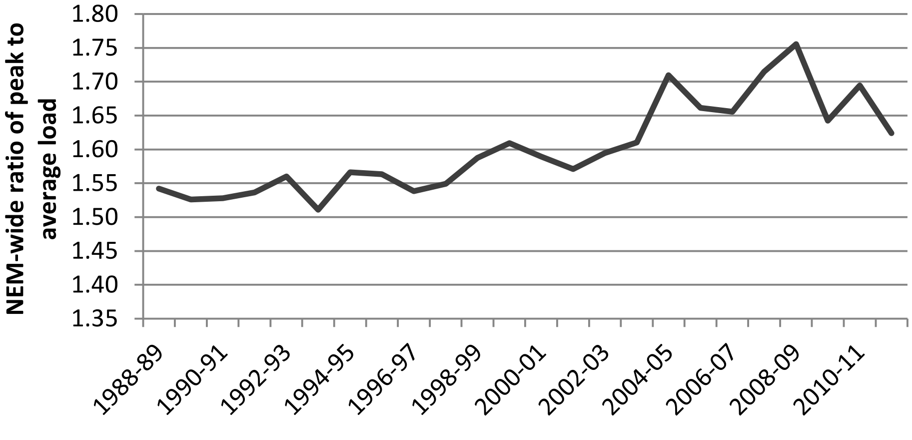
6 An exception is when the security of the NEM is under threat due to an imbalance between available supply capacity and demand at any instant, which can call for shedding of a threshold volume of load to prevent system failure.

Peak demand is growing and becoming more 'peaky'

While determinants of peak and average demand overlap (box 9.1), 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 *Electricity Gas Australia*, various issues.

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

Box 9.1 Determinants and forecasts of demand

The growth of peak 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 the average demand for electricity drawn from the network that is supplied by traditional large scale generators, but have less impact on reducing peak demand
- 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, and changing consumer preferences.

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.

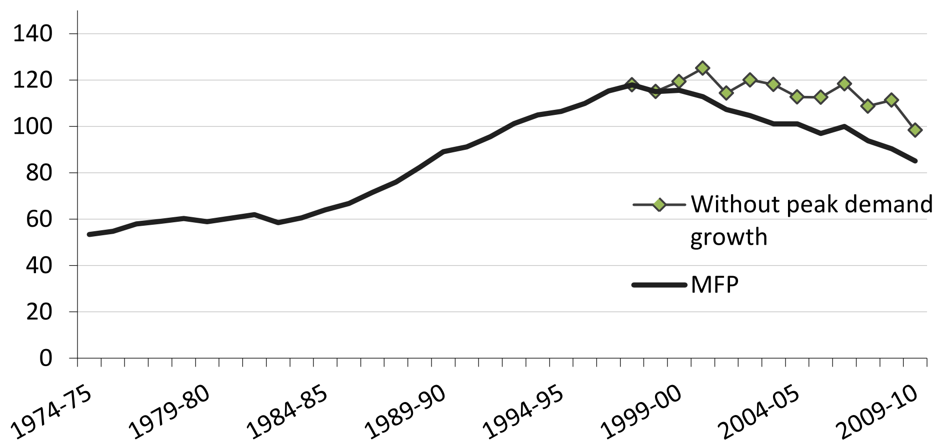
Growth in peak demand is forecast to be lower than in previous years, but is projected to continue to grow in the longer term (AEMO 2012a). Over the next 10 years, annual growth in peak demand across NEM regions is forecast to range between 1-2.5 per cent. This forecast is a revision on previous estimates, 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 10 years. These estimates, though, are sensitive to the incidence of extreme daily temperatures.

Annual energy (or average) consumption is projected to be 2.4 per cent lower in 2011-12 than 2010-11, and over the next 10-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.

While long-term forecasts of peak demand generally assume continued long-term growth, most regions of the NEM experienced relatively mild summers in 2010-11 and 2011-12, which resulted in a lower rate of peak demand growth compared with earlier years (box 9.2). 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), which 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 ratio of average to peak demand (also referred to as the 'load factor' or the peakiness of demand) significantly affects the cost of supplying electricity. As an indication of the long-term gains from reducing peak demand (and narrowing the gap between average and peak demand), a move from a 38 per cent to a 50 per cent load factor would reduce an average electricity bill in 2015 by about $245. This is equivalent to about $1.6 billion per annum across the NEM (Simshauser 2012).

Box 9.2 **The cyclical impact of climate muddies the long-term trend**

Peak electricity demand in Australia is most common on very hot days. In 2010-11 and 2011-12, there was a decline in the frequency of very hot days. However, 2013 has produced the hottest January on record. A recent publication by climate scientists provides a longer-term context to these recent weather events. In the most recent *State of the Climate* report, the CSIRO and the Bureau of Meteorology 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 Niña 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 Niña events. (2012, p. 3)

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

Australia's seasonal climate is inherently variable

Average number of days over 40°C

The decline in the number of very hot days in 2010 and 2011 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 those in 1999 and 2000), when there was a reduction in the frequency of very hot days, highlighting the substantial impact that climate variation has on weather events in different years. As such, in future, the frequency of very hot days is projected to increase.

Sources: BoM (2012); CSIRO and BoM (2012).

Household usage is a major contributor to peak demand

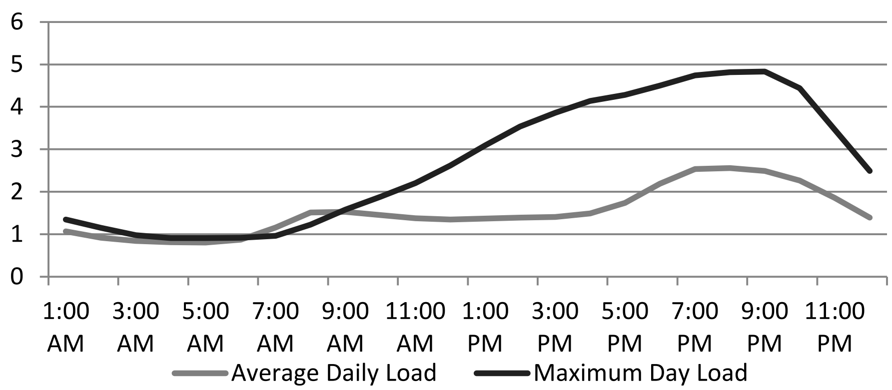
Household consumption accounts for less than one-third of total electricity use but has important implications for peak demand, with some estimates showing it may account for more than two-thirds of peak loads (NERA 2008a). Of course, the contribution to peak load at a given network asset may be much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



[a] Based on interval meter data from 3000 Sydney households in the financial year 2010. The maximum day load is the load profile for the day of maximum peak demand for the financial year, while the average daily load is the average for all days in that year.

Data source: Simshauser (2012).

Factors that affect household electricity use during peak periods may include consumers' income,[7] 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-

[7] 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).

initiated energy efficiency programs (although each of these factors has primarily affected average demand, with a lesser effect on peak consumption).

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, p. v). Households are willing to reduce their power usage under the right circumstances. An ABS survey (though rather dated), found that 88 per cent of households had taken steps to limit their power use and conserve energy due to price rises and other, largely environmental, reasons (ABS 2010). Higher prices will also encourage some reduction in consumption during peak demand periods. However, if higher prices came in the form of a flat network charge, consumers would likely reduce their demand across all periods, with only a modest reduction in peak demand.

Demand management tools targeting peak consumption are much more likely to be effective. The tools include critical peak pricing (higher prices during periods of peak demand) and direct load control (where consumers agree to have some of their electricity use curtailed at peak times).

Currently though, even where metering allows 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 charges).[8] 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:

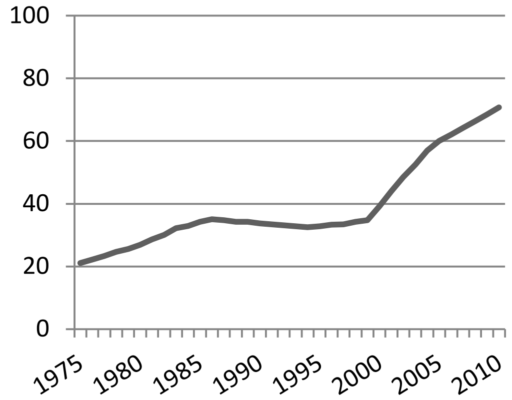
> The increasing penetration of air conditioning, particularly in the residential sector, has been cited by network businesses as a key reason for increasing maximum demand. (2011a, p. 10)

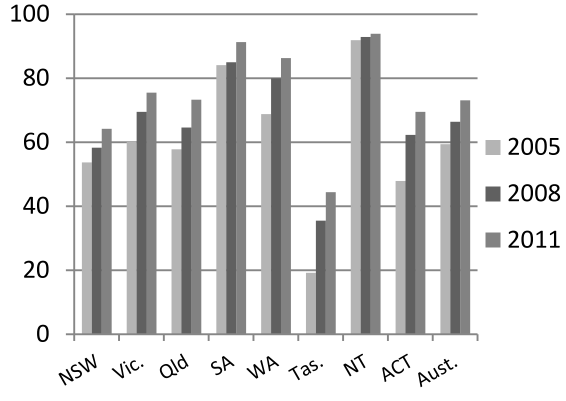
The extent of this growth is shown in figure 9.7.

8 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.

Figure 9.7 **The increase in household air conditioning**

Per cent of households with air conditioning





Data sources: ABS (2011d), Topp and Kulys (2012).

The national stock of air conditioners doubled in the 10 years to 2008, and by 2020, the associated use of electricity is projected to be five times greater than it was in 1990 (DEWHA 2008, p. x). Rising incomes, hotter weather and the declining cost of air conditioners are key causes of this trend. Other factors include new homes that are much larger than in the past[9] 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 affect their contribution to peak demand and, in turn, network costs.[10] 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.

9 The average size of new dwellings is increasing rapidly. From 1986 to 2020, the total floor area of residential dwellings is expected to increase by 280 per cent (DEWHA 2008, p. x).

10 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 six years (Galaxy Research 2012). However, a move to more cost-reflective prices would provide a strong incentive for consumers to choose more energy efficient appliances when their air conditioners reach the end of their life and need replacing. The type of appliance is also relevant. Most households operate split-system (non-ducted) reverse cycle types, which have lower energy efficiency than an evaporative cooler (Graham Palmer, sub. DR46, p. 2). Only around 5–6 per cent of new air conditioning sales are for the more energy efficient evaporative systems, although these are not suited to all climates.

Most other household appliances (such as refrigeration) have a much flatter load profile, with a load factor of around 60–70 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 has been estimated that a 2 kilowatt (electrical input) reverse cycle air conditioner could impose a system-wide cost of up to $7000 (DRET 2011).[11] 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 fails to take account of the different asset lives of air conditioners and the infrastructure in the electricity system that provides capacity
- it assumes that the appliance is always operating during peak demand periods — about 30–35 per cent are normally turned off (CRA 2006; Swift 2005)
- 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 after allowing for these factors, a crude estimate of the system-wide cost of a reverse cycle air conditioner that is used mostly during peak times is probably still around $2500. This estimate represents an implicit subsidy of

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11 The $7000 cost is derived from Energex estimates (Queensland Department of Employment, Economic Development and Innovation 2011, p. 4), which indicate that the costs of adding 1 kW of capacity (including all network and generation costs) is around $3500 for the life of the network and generation assets. (The Commission cites a wider range of figures later in this chapter.) However, the life of an air conditioner is considerably shorter than the life of the assets supplying additional capacity, and so it is incorrect to attribute all of the capacity charges to a single air conditioner.

$350 per year to customers who own and use air conditioners at peak times, paid for through higher bills for all other customers.[12]

Reasons and scope for change

Flat network tariffs effectively 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 with 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 2009, 2010).

More recently, the growth in the number of households with air conditioning has started to slow and may 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 3–6 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 Charles River Associates, in evaluating feasible demand management options:

12 Modelling undertaken by Charles River Associates for Endeavour Energy using a long run marginal cost approach for capital investment to meet peak demand indicates that the cross-subsidy between customers with air conditioning and those without is $80–$110 million per year — or approximately one third of total sales to the residential and small business sectors. If this subsidy is smeared across all of the remaining consumption by these groups it equates to 1.5 cents/kWh to 2.0 cents/kWh relative to the marginal rate (Endeavour Energy 2012b, p. 43). Based on an average household consumption of 7500 KWh pa (Simshauser 2012), this range represents around $112–$150 per annum.

> … [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 … (CRA 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 9.6). 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 management[13] offers a potential solution to the problem of peak demand by providing incentives for consumers and businesses to reduce consumption at 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 shifting the timing of electricity use and reducing 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 (such as open cycle gas turbines)
- improve competition and reduce the ability of an individual generator to exercise market power in the wholesale market during congestion at peak periods

13 The literature does not adopt a consistent nomenclature. In this report, 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).

(Borenstein 2005; Borenstein and Holland 2005; Bushnell 2005; Joskow and Wolfram 2012)

- 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 large 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.[14] 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 combine with information-led behavioural change. Some measures will be more effective at targeting peak consumption than others, and each will involve different costs to implement. For example, many energy efficiency measures have a

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.

‘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**

Name	*How it works*	*Technologies involved*
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 assist consumers to respond. For example, in-home displays and whole house gateway systems allow appliances to be individually controlled and automatically adjusted in response to prices. Web portals, SMS and email technologies 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’.
Distributed generation (chapter 13)	Produces 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	Lowers the electricity demands of appliances, including during peak events.	Wide ranging. Many approaches do not have a targeted impact during peak events.

Source: EnerNOC (pers. comm.).

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 9 PM. encouraged many people to delay their (then expensive) long-distance telephone calls. Although not used extensively to date in Australia to manage the electricity demand of 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 and Palmer 2012; Futura 2011). (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. (SCER 2011a, p. 16)

Box 9.3 **Consumption responsiveness to time-based prices**[17]

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; Futura 2009; NERA 2008b)
- households are generally less responsive to high peak charges during winter, which is relevant to some regions in New South Wales 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 and Binz 2011; Caves et al. 1984; Faruqui and Palmer 2012; Faruqui and Sergici 2010; Simshauser 2012). 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 than among those facing a ratio of 13:[18]
  - 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 of 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 adapt the pattern and timing of their electricity use, or pay the true cost-reflective price for their consumption during peak times. Thus, the scale of demand management is particularly important. Allowing consumers to ‘volunteer’ to face the true costs of their consumption is likely to lead to a low uptake and a low level of consumption response.

Box 9.4 **Behavioural traits would not preclude cost-reflective pricing**

While price signals guide many aspects of consumption and production in advanced economies such as Australia, it is sometimes asserted in debates about electricity market reform that consumers either would not or could not respond to time-based tariffs and adapt the timing of their power use. 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 cognitive limitations and behavioural biases in several settings (for example, 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 considers that they would not preclude responses 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 fruit and 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 lack of interest 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.

Most importantly, the empirical evidence demonstrates that whatever people's behavioural biases, they *do* reduce energy use in response to time-based pricing (box 9.3).

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 between 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 little to 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. (AER 2012d, p. 3)

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

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; volume 2 of Deloitte 2011b, p. 109).

meet that over-consumption, and results in network prices being higher on average than they need to be over the longer term.

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 noting 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 — smart meters — are available in much of Victoria, policy decisions have so far prevented their use for efficient pricing.[20]

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' (TOU) network tariffs. (For example, Ausgrid anticipates 400 000 residential users will face a TOU network tariff by mid-2013.) However, the structure of the tariff is likely to have only a minimal impact on peak consumption (figure 9.8 shown later). This is because 'peak' periods are usually set as a routine six to seven hour window 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.

20 Such meters can usually communicate prices in half hourly 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.

Most network businesses have undertaken trials of more cost-reflective pricing structures, including of critical peak prices. Reductions in peak electricity demand during these trials have typically ranged from around 20–40 per cent.

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. Its business customers have faced such tariffs since 2010-11, which apply to a four-hour window on no more than five declared critical event days. The demand effects can be large. For example, SP Ausnet introduced a cost-reflective tariff, including a critical peak price, for commercial and industrial customers consuming more than 160 MWh per year (around 1800 customers). Around two-thirds of the 1800 customers responded by reducing demand, of which 300 reduced peak demand by more than 50 per cent, and 75 by more than 90 per cent (Futura 2011, p. 47). However, the timing of the 'critical peak' was applied universally across the SP AusNet network and, hence, did 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 that large commercial and industrial users can face, unless they take steps to reduce their effective exposure.

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 face 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

Under the National Electricity Rules, network businesses are required 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.

Network businesses investigate various demand management solutions (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 for its potential 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 11 kV 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 three 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 implemented**
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 [a]	$ million	3.95	2.75	1.37
Project savings from deferral [a]	$ million	13.40	6.46	4.17
Proportion of augmentation capital allowance	Per cent	3.60	1.30	0.70

[a] Of implemented projects.

Source: Ausgrid (2011c, p. 12).

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, electricity demand in Tasmania is dominated by four large industrial businesses (ESIEP 2012a), with whom agreements can be reached (usually at low cost compared with smaller users) to curtail their use of system capacity upon request[22]
- 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. There have been extensive trials of load control of such appliances that have demonstrated their technical feasibility, consumer receptiveness to control and the degree of demand response. Results from the trials suggest that a major reduction in the normal peak operating load of air conditioners may be achievable — equivalent to 20–30 per cent reduction in the peak demand of the trial households (Futura 2011, p. 60). Some network businesses are now introducing direct load control options into their customer offerings. For example, in Queensland, Energex is currently subsidising the installation of air conditioners whose power can be capped at times of network congestion (chapter 10)
- commercial building energy efficiency programs. Cost-effective options usually target lighting upgrades. A previous project by EnergyAustralia 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.

Sources: EnergyAustralia and TransGrid (2009); ESIEP (2012a); Futura (2011).

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 risk of a demand management solution not meeting the agreed reduction in

22 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.

demand.[23] 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) typically amounts to thousands of dollars per site. Consequently, five-year contracts are normally established with end-users.

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 367 MW, and more than four times higher than in 2008-09) (Dunstan et al. 2011a, p. vi).

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 was sourced from commercial and industrial customers,[24] which is equivalent to around 1 per cent of system peak demand in the NEM. Similarly, an annual survey undertaken by AEMO of demand management by retailers, network businesses and demand response aggregators indicates that the level of demand response amounts to less than 1.5 per cent of the NEM-wide peak (table 9.3; AEMO 2012a).[25] This level appears low compared with international benchmarks. For example, in California the equivalent peak load reduction is 6 per cent (Faruqui and Fox-Penner 2011, p. 46).

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

	Very likely	*Even chance*	*Very unlikely*
Queensland	78	111	111
New South Wales	31	71	98
Victoria and South Australia	109	121	149

Source: AEMO (2012a, p. D-2).

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 the following price spikes in the spot market in New South Wales:

23 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.

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

25 This level represents the full amount of the 'very likely' demand response and 50 per cent of the 'even chance' demand response, as a proportion of the maximum demand for each jurisdiction.

- 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).

These 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), this evidence suggests a greater source of demand response capacity for networks to tap into.

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 interval meters — and particularly remotely-read or 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 and some regulatory arrangements act as barriers to their installation (chapter 10)
- where smart meters are available for residential customers, their use for demand management may be restricted. For example, although smart meters have been installed across Victoria, the state government imposed 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, in some cases, have the unintended effect of limiting the incentives of distribution businesses to implement demand management solutions, even where they offer the most efficient solution (AEMC 2012u) (chapters 5,10 and 12)
- distribution businesses are concerned about the risks of 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, pp. 11-12)

- the perception that customers will not respond to prices or other market-based incentives to shift loads. This assumption is not supported by trial evidence, which shows consumers 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). These factors introduce uncertainty around whether retailers will pass on cost-reflective network charges
- 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 always 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 potentially billions of dollars of network investment, for which consumers ultimately pay.

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 system — where expansion of peak capacity only occurs to the extent that 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 information technology (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 is likely 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 appliances, 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 (CRA 2006, 2008a, 2008b; Deloitte 2011a; EMCa 2008; ESC 2002, 2004a; KPMG 2008; NERA 2008a, 2008b). 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 recommendations.

To those ends, the Commission has compiled indicative estimates for a number of demand management initiatives.[26] The analysis incorporates estimates of untargeted 'time-of-use' pricing, direct load control and critical peak pricing. 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 net benefits of demand management depend crucially on the manner in which demand management is implemented (with indicative estimates of the outcomes shown in table 9.4).

- If a smart meter rollout is implemented efficiently and targeted at regions where capacity constraints are impending, then the relevant households could get a stream of benefits that add to around \$900–\$1900 per household in net present value terms. This stream of benefits is equivalent to an *annual* benefit of around \$100-\$200 over the life of the meters.[27] The benefits arise mainly from deferring network augmentation (as discussed further below) and from savings in the operating costs of networks (such as remote reading of meters and fault detection).
- There is a substantial risk that a fast-tracked NEM-wide smart meter rollout would impose net costs. This reflects that an immediate national smart meter rollout would involve high upfront costs, but limited savings from deferred network augmentation in the many areas where there are no immediate network constraints.
- A meter rollout combined with weakly targeted time-of-use tariffs would fail to generate a significant demand response, so that most of the benefits of a rollout would be derived from savings in remote meter reading and other network operating costs, rather than deferring network investments. The most likely outcome would be a net cost.

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[26] These are contained in the Commission's technical supplement on the costs and benefits of demand management. This supplement is available on the Commission's inquiry website.

[27] While not enumerating the household benefits of particular demand management initiatives, the AEMC (2012u, p. 259) found significant savings from what appear to be achievable reductions in peak demand. It estimated that for a typical average annual consumption level of 8 MWh and retail bill of \$2000, reductions in peak consumption of around 14 per cent to 18 per cent of original usage during the peak period (between 2 pm and 8 pm) would achieve savings of around \$200 on an annual bill. The present value of this saving is around \$2500 per household).

- Implementation of direct load control of air conditioning is likely to produce significant net benefits, though the pace of adoption of this technology depends on the share of new air conditioners with an in-built compatibility with direct load control.

The results highlight the importance of a more targeted approach to where and when investments in smart meters (or other demand technologies) occur.

Table 9.4 **Relative merits of stylised demand management approaches**
Benefit–cost ratios, indicative estimates[a]

Scenario	*Low*	*Mid-point*	*High*
National smart meter rollout with critical peak pricing	0.6	1.2	2.7
National smart meter rollout with untargeted time of use pricing	0.3	0.6	1.1
Direct load control in the absence of smart meters	1.2	2.7	6.3
Smart meter rollout in areas with network constraints, accompanied by critical peak pricing	1.1	2.7	6.9

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 from the technical supplement on the costs and benefits of demand management.

As discussed at length in the technical supplement, there are uncertainties about the magnitude of the costs or benefits attached to some of the key components of the estimates in table 9.4. Over time, and with iterative experiences in implementing demand management approaches, it should be possible to identify a narrower range of estimates. These uncertainties also imply that a one-off decision for a mandatory rollout of smart meters in a given period across a whole state (as occurred in Victoria) should be avoided. Such a universal rollout loses the option value of waiting for new information about costs and benefits, and from determining the best sequencing and location of meter rollouts. Chapter 10 discusses the appropriate regulatory arrangements to maximise the net benefits of smart metering rollouts.

As discussed earlier, there is further scope for gains from the nearer-term adoption of more efficient time-based network pricing for commercial and industrial end-users, which the Commission has not modelled.

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 many estimates of the long-run marginal cost of delivering an additional kW to an end user during critical peak periods[28] and found the following ranges plausible:

- $150–$220 of distribution infrastructure costs for an additional kW per year
- $30–$70 of additional generation capacity costs for an additional kW per year
- $90 of transmission infrastructure costs for an additional kW per year.

This suggests that, in aggregate, the long-run marginal cost of adding the capacity to deliver power to consumers at critical peak times is likely to be somewhere in the range of $270–$380 per kW per year.

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 is 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).

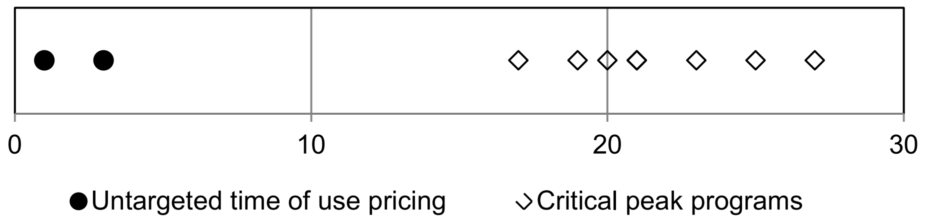
The reduction in energy use during critical peak events has been substantially lower under untargeted TOU schemes than under other demand management schemes (figure 9.8). Untargeted TOU charging is less effective than other demand management approaches because:

[28] The information was obtained from personal communications with various network businesses; network business pricing proposals; Futura (2009); Oakley Greenwood (2010b); Deloitte (2012), and the Queensland Department of Employment, Economic Development and Innovation (2011).

- the price variations between 'peak', 'shoulder' and 'off-peak' times are relatively shallow
- the peak periods are relatively long (typically applying for 1000–1600 hours per year) and do not target critical peaks (typically 40-80 hours a year)
- while TOU prices and periods may change during the year — reflecting seasonal patterns of demand — they usually do not change more than twice a year.

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 rollout 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) or have a disproportionate number of participants who are interested in energy conservation (Futura 2011; Graham Palmer, sub. DR46, p. 2). 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. Therefore, lower reductions in peak energy use may be achieved outside of trial settings.

Smart meters are a crucial cost item

Implementing sophisticated 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. In contrast, for the residential and small business customers in the NEM currently using traditional 'accumulation' meters (box 10.1 in chapter 10) the transition costs to adopt smart meters can be significant.[29]

In Victoria, the rollout cost around $800 per meter, with further ongoing operating costs of $20–30 per year.[30] This is greater than the 'building block' forecasts produced by Energy Marketing Consulting associates (EMCa 2008), which suggested costs of 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. However, the extent to which smart meter prices may fall is uncertain.

Smart meters would provide other benefits

A smart meter rollout also offers the potential to deliver other benefits that are largely unrelated to demand management (Deloitte 2011a, pp. 58-66, 73-80). While the list of other benefits is long, they include improvements in network management and efficiency, such as:

- manual reading of accumulation meters should not be required
- disconnections and reconnections and of special meter reading (such as when consumers dispute their bills) can be conducted remotely
- networks can detect outages almost immediately, and faults can be diagnosed more rapidly, allowing them to respond more quickly and cost effectively.

Recent Australian studies provide varying estimates of these other benefits (CRA 2008a; Deloitte 2011a; Futura 2009; NERA 2008b; Oakley Greenwood 2010b). The most recent of these studies (Deloitte's analysis of Victoria's smart meter rollout) indicates that these other benefits can exceed those derived from innovative tariffs and demand management (AEMC 2012d, p. 8).

However, these estimates are for a mandated system-wide rollout. The Commission's approach would encourage localised rollouts that target areas where the network is approaching capacity and, where otherwise, network augmentations would occur. Under these circumstances, the benefits from deferred network augmentation would be realised relatively quickly. In contrast, under a mandated rollout, many regions would have significant spare capacity, so that there would

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29 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.

30 This compares with the replacement cost of an accumulation meter of around $170 (this covers the cost of the meter and the cost of installing the meter) (AEMC 2012y, p. 2).

often be no immediate potential for deferring investment. Under the Commission's approach, bringing forward these deferral benefits increases their net present value and, commensurately, reduces the proportion of the total net present value of benefits derived from other benefits (box 9.7).

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 evidence suggests that the costs in the Victorian rollout were higher than anticipated, and their effective use has not yet been realised. 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 responding to price signals and adapting their consumption habits, and doing so in a timely manner. 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 main benefits of pricing reform in the medium term and jeopardise the cost-effectiveness of smart meter investments.

Box 9.7 **Timing of benefits differ for mandated and targeted rollouts**

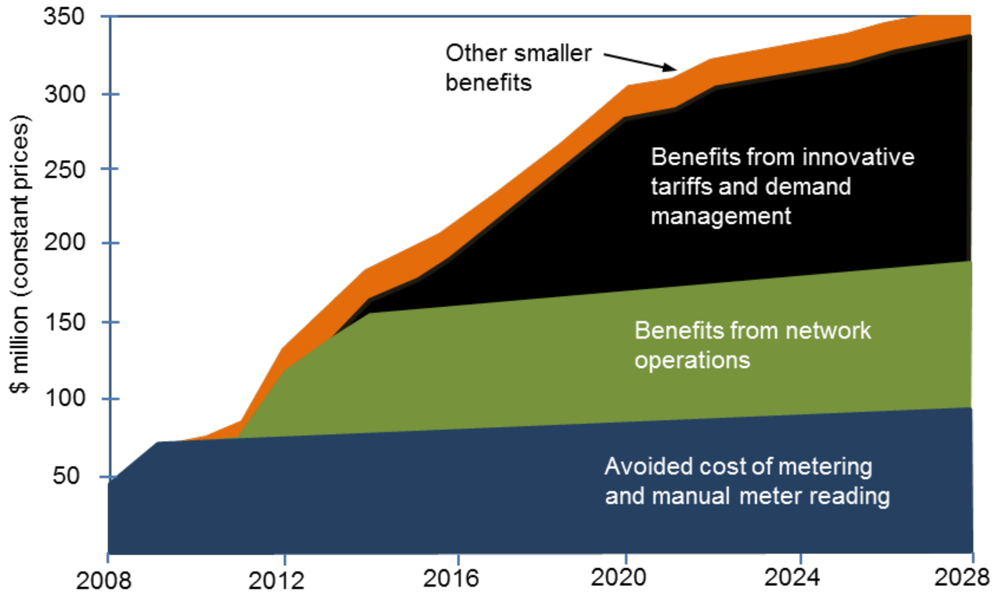
The benefits of a smart meter rollout can be categorised into four broad areas:

- benefits generated by innovative tariffs and demand management
- avoided costs associated with accumulation meters resulting from the rollout
- benefits derived from efficiencies in network operations
- other minor efficiencies in network and retail operations.

Deloitte (2011a) estimated the mix and timing of benefits for Victoria's mandated rollout of smart meters (see figure below). This figure shows that the benefits from innovative tariffs and demand management take time to emerge fully, whereas benefits from, for example, avoided costs of meter reading and from more efficient network operations are realised from at or near the start of any rollout.

Estimated value of Victorian rollout benefits over 2008–28

Net present value, 2008 prices



By comparison, a localised rollout that targeted areas where the network is at, or approaching, capacity could be expected to realise the benefits of deferred network augmentation in the early years of the rollout rather than later, which would be the overall result under a mandated rollout. In terms of the figure above, this would have the implication that the contribution of innovative tariffs and demand management to the overall benefits would be closer to that shown for 2028.

Source: Deloitte (2011a, pp. 58, 83).

10 Technologies to achieve demand management

Key points

- Demand management technologies — particularly advanced metering — underpin efficient network pricing and improved operational efficiencies for network businesses, provide information to customers and retailers, and, over the longer run, can contribute to the development of a smart grid.
- The deployment of demand management technologies is frustrated by several obstacles, the most important of which are that retail price regulations stymie time-based tariffs and that the benefits are split amongst many parties.
- Nevertheless, the efficiencies from smart meter deployment are mainly associated with electricity distribution networks. These efficiencies are determined by the pace and location of smart meter rollouts and, over the longer run, their integration into the smart grid. Given this, network businesses should be the prime (but not exclusive) decision-makers. To achieve this:
  - minimum functionality smart meters should be treated like other distribution network assets by the Australian Energy Regulator (AER) in regulatory determinations, with distribution businesses free to determine the location and pace of their rollout — as with other demand management options
  - the National Electricity Rules would need to change as they currently limit the capacity for distributor-initiated smart meter rollouts
  - incentive arrangements intended to address the wider efficiency gains of demand management in other parts of the energy supply chain would need to be strengthened.
- Smart meters should be subject to an appropriate minimum standard (preferably internationally accepted) that allows interoperability with add-on technologies, and allows several parties to access data. Distributors should not have a monopoly on the provision of advanced metering infrastructure, with third parties also able to install add-on technologies and higher-functionality smart meters. Retailers are likely to play a major role in this regard.
- Like all other network investments, consumers will ultimately bear their costs, but in many cases, the costs could be recovered from electricity bills over many years and would be more than offset by the benefits. The rollout of metering technologies needs active community consultation and communication.
- Direct load control of electrical appliances — especially air conditioners — can be a substitute or complement to smart meters, but mandating standards that Australian electrical appliances have to be compatible with direct load control is not justified.

Electricity demand management relies on technology solutions to achieve time-based pricing, to support load management and to provide information to consumers so they may increase their energy efficiency. Advanced metering infrastructure —'smart' meters'[1] — is the cornerstone of such technology solutions. As well as having several other important functions, the meters make it possible to set prices that reflect the true costs of supplying power at a given time — 'cost-reflective' prices (chapter 11). The evidence suggests that when faced with cost-reflective prices, many people would lower their consumption at peak times, reducing the network investments needed to meet demand during these periods, and placing downward pressures on their electricity prices. People choosing to maintain their consumption during peak periods would pay a higher price, which would fully reflect the costs of network provision at those times, and eliminate current cross-subsidies. Network prices at non-peak times would be considerably cheaper. Other technologies that remotely control the power usage of certain appliances ('direct load control')[2] — such as air conditioners — can also reduce peak demand and lower network costs, and are often complements to smart meters (figure 10.1 and section 10.7).

As discussed in chapter 9, there is considerable uncertainty about the costs and benefits of specific demand management options, including how these might change over time. There is also uncertainty about the extent to which consumers might respond to demand management options, and the role of supporting technologies in assisting behavioural change. Further, changes to the patterns of electricity use, such as from the uptake of electric vehicles, could potentially exacerbate peak demand or, if carefully managed, provide an opportunity to smooth consumption.

Notwithstanding these uncertainties, the efficient implementation of supporting technologies and price signals will be fundamental to reducing peak demand and network costs. Any rollout of these technologies will need to be supported by appropriate regulations and processes — the focus of this chapter.[3]

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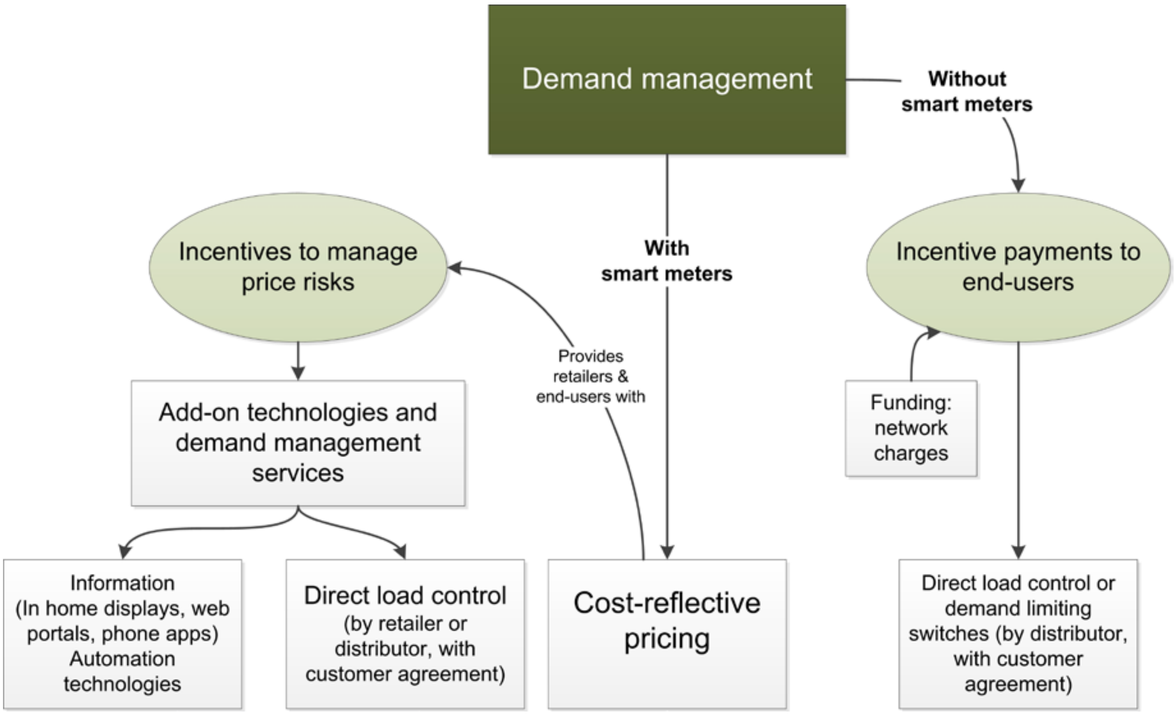
1 The term 'smart meters' is used to describe the smart meter itself, and associated technologies, such as IT equipment, back end software, and two-way communication equipment. Smart meters come in several forms, but all can be remotely read and provide details of consumption over time. Manually-read interval meters ('type 5' meters), also allow time-based charging, but cannot provide timely feedback to consumers, facilitate direct load control, or provide a range of other efficiency benefits to distributors.

2 Achieved through a 'demand response enabling device' (DRED), as described in box 10.6 at the end of this chapter.

3 The term rollout 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 rollout throughout an entire jurisdiction.

Section 10.1 provides background to smart metering technologies and recent experiences with their implementation. Section 10.2 looks at the challenges of installing smart meters, while section 10.3 examines various models for deploying smart meters and their advantages and disadvantages. Section 10.4 details a ‘hybrid’ approach that draws on the best features of these models, while reducing their downsides. It is important that rollouts are not just distributor-centric, but take account of other parties, most especially consumers (section 10.5). Section 10.6 outlines issues relating to the information hub that would underlie a smart meter network. Finally, direct load control of appliances can act as a substitute or complement to smart meters (section 10.7).

Figure 10.1 **Technology pathways to achieve demand management for residential consumers**[a]



a The chart (and this chapter) focuses on low energy-using household and small business customers. Smart metering and other demand management technologies are also applicable to industrial and commercial customers, but many of these already have the metering technology and are exposed to time-varying prices (chapter 11). Such parties (or aggregators acting as intermediaries for them) may also have load shedding agreements with networks or, depending on developments in the regulatory framework, may be able to offer their demand responses as a de facto generator in the wholesale spot market (AEMC 2012u, p. 112). The Australian Energy Market Commission has examined these issues in detail.

10.1 Understanding smart meters

Smart meters can promote better demand management and operational efficiencies

Smart meters measure and record users' consumption of electricity over 30-minute intervals (which is a requirement for cost-reflective pricing) and are capable of being remotely read. (Box 10.1 describes the various types of metering installations; of which types 1 to 4 qualify as 'smart meters'.)

Smart meters require a relatively large outlay, but they can provide versatile demand management options. They allow two-way flows of information that, in addition to facilitating time-based pricing, can allow:

- control of customers' equipment, such as direct load control of air conditioners and pool pumps, subject to those customers' agreement
- interactions with consumer 'add-on' technologies to enable automated 'set and forget' controls for equipment and appliances, and to inform a customer's energy use decisions. In that vein, current options include in-home displays, web portals or via a home 'gateway' — a connection between the smart meter and a home computer and the internet. For example, Origin Energy, Jemena and SP AusNet in Victoria have provided web portals for customers who have a smart meter installed (DPI 2012c).

These demand management options can help reduce the 'transaction costs' for consumers in responding to price signals and, hence, can elicit a higher level of demand response than might otherwise be the case. For example, they can eliminate the time and inconvenience consumers might incur in managing their electricity use by providing 'no-fuss' automated solutions.

Smart meters produce significant efficiencies in electricity networks (and to a lesser degree) through the energy supply chain more generally, such as:[4]

- lower meter reading costs. For example, Futura (2009, p. 90) estimated that the Victorian rollout would produce meter reading savings with a net present value of between $430 and $520 million in 2009 prices
- savings through remote connections and disconnections
- reduced call centre costs, for example in relation to complaints about billing errors

4 For example, see Futura (2009), Giordano et al. (2012) and Oakley Greenwood (2010b).

Box 10.1 **Metering installation types**

The type of metering installation and its accuracy requirements are determined in accordance with the National Electricity Rules and depend on the size of the load.

Size of load (annual energy consumption)	*Metering installation type*
Greater than 1000 GWh	1
Between 1000 GWh and 100 GWh	2
Between 100 GWh and 750 MWh	3
Between 750 MWh and zero	4, 5, 6 and 7

Smart meters — types 1 to 4

Type 1 to 3 metering installations must be capable of:

- measuring active (kW) and reactive energy (kvar) and include facilities for storing interval energy data for at least 35 days
- measuring energy in 30 minute intervals in both directions
- being remotely read (that is, data extraction via a communications link).

Type 4 meters are similar to types 1 to 3, but are intended for low power-using consumers and are not required to measure reactive energy (Ausgrid 2012e, p. 10; Gill 2011, p. 7). While the current from reactive power does no work at load, it heats the wires, and wastes energy — hence the value of measuring it.

Old style meters — types 5 and 6

Type 5 and 6 metering installations are older technologies with functions that reflect the historical nature of the grid and pricing practices.

- Type 5 metering installations are manually-read interval meters and include facilities for storing interval data for at least 200 days. These can support time-based charges.
- Type 6 metering installations are manually-read ‘accumulation’ meters that record total energy consumption, but not its time of use.

Sometimes terminology muddies the waters

There are also so-called type 7 ‘metering’ installations. These are actually unmetered and relate to small and predictable loads, such as street lights, illuminated signs, and sprinkler control systems, where usage is not recorded (AEMO 2009b, pp. 76ff).

Moreover, some meters labelled as type 5 (Kema Australia 2013, p. 4.41) are actually type 4 meters in their technical capacity. In a regulatory peculiarity, Type 4 meters rolled out mandatorily in Victoria were given honorary status as type 5 meters to comply with the National Electricity Rules. As discussed later, type 1 to 4 meters are treated as contestable in the Rules, so that prime responsibility for the meter does not lie with the distributor. The Victorian Government received a derogation to the Rules to establish the capacity for the distribution business to be the exclusive responsible party for what are technically type 4 meters, with this achieved by re-labelling the meter type (AEMC 2008e).

Sources: AEMC (2008e, 2012d); AEMO (2009b); Ausgrid (2012e); Kema Australia (2013); National Electricity Rules v.54.

- lower operations and maintenance costs, such as quicker detection of network anomalies and reduced amount of time between a breakdown and restoration of supply — part of the real time management of the grid (the 'smart' grid)
- deferred and avoided capacity investments in distribution and transmission networks and in generation
- improved voltage control and other reductions in electricity technical losses
- ability to measure power (by time) that is locally generated and exported into the distribution system, for example by a solar photovoltaic (PV) roof top unit
- lower theft rates of electricity
- ability to set emergency demand limits to share limited supply at times of network stress or supply shortages
- improved hedging and reduced cost of billing inquiries and bad debt for retailers.

Various participants in this inquiry indicated how these benefits arise:

> … [Smart meters] can also provide 'real time' information on the operation of the distribution system, which allows companies to locate faults that lead to power interruptions more quickly and accurately. … [this] can be used to optimize the size and dispatch of work crews, thereby reducing operating costs. [Smart meters] can also monitor the loading and condition of distribution system components, which can help companies optimize their inspection and maintenance cycles as well as extend the periods for replacing capital equipment. Automated meter reads also tend to improve billing accuracy and the timeliness with which bills are produced … In addition … more sophisticated metering systems will be increasingly necessary for distributors to cope with the more diverse and 'distributed' (i.e. less centralized) nature of new generation technologies. (Pacific Economics Group, sub. DR48, p. 7)
>
> NSP's [Network Service Providers] are suffering from a lack of detailed information about behaviours and the contribution of new consumption and production technologies at the consumer level. While smart meters alone will not solve these problems, the information and capabilities that can be provided [by these meters] and utilised by NSP's will be a key enabling technology for increased network utilisation and reliability. (Sinclair Knight Merz, sub. DR61, p. 6)

Most Australian households outside Victoria do not have smart meters (or even non-remotely read interval meters). As a result, few households face time-based tariffs for their electricity use.[5] Only in Victoria is the smart meter household penetration rate high. However, a government-imposed moratorium on time-based tariffs for residential users in Victoria applies until the middle of 2013, at which

5 With the exception of an off-peak tariff for directly wired electric hot water services. Kema Australia (2013) has detailed information about the deployment of smart meters throughout the NEM, and the extent to which they support time-based pricing.

point customers may voluntarily switch to a simple time-based tariff (O'Brien 2012). (Meanwhile, customers are paying for the cost of their installation, adding around $25 a quarter to households' electricity bills.) In contrast, a much higher share of business users have smart meters and, to varying degrees, already face time-based prices.

Mixed results from rollouts and uncertainties about costs and benefits

Smart meters are a relatively new, but not revolutionary, technology. The associated hardware, information technology (IT) and communications technologies are continuing to mature, which is consistent with declining costs (or stable costs with increasing functionality) over time. For example, Frost and Sullivan (2011) estimate that the price of smart meters in the European market will fall by over 30 per cent between 2010 and 2017. This is mainly a consequence of scale economies, with two providers serving 90 per cent of the European market.

Evidence about the role of smart meters in demand management is increasing with the completion of a number of large-scale rollouts. Smart meter rollouts have occurred or are occurring in many European countries, including France, Italy, Spain, Sweden, the Netherlands and, more recently, in the United Kingdom.[6] Smart meters are also common in many areas of the United States and Canada. The most prominent Australian example of a broad scale rollout is in Victoria.

International and Australian experience demonstrates that a carefully managed implementation is crucial to realise the potential net-benefits from smart meters. For example, the rollout in Victoria faced multiple setbacks, including implementation costs that exceeded original estimates (box 10.2). The benefits from the Victorian rollout 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 Commission's attempt to quantify the costs (and benefits) of smart meters revealed a wide range of potential estimates (chapter 9). Implementation costs are sensitive to small changes in a range of assumptions, including:

- the density of a rollout and the topography, which affects:
  - the feasibility of different communications technologies (given the technical performance and associated cost of options)

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[6] The United Kingdom is commencing a rollout 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 £7.2 billion (DECC 2012).

Box 10.2 **The Victorian smart meter rollout**

In 2004, The Essential Services Commission (ESC 2004a) proposed the mandatory rollout of (technologically-proven) manually read interval meters, which would enable time-based charging. However, in response to a study of the incremental costs and benefits of more advanced metering (CRAIIC 2005), in 2006, the Victorian Government directed distributors to install 2.4 million smart meters in Victorian homes and small businesses from 2009 to 2013, with customers to pay the costs directly. The Government did not impose a particular technology for the smart meters installed, although it did prescribe a relatively high level of minimum functionality of the meters and standards for associated service levels (DPI, pers. comm., 28 Feb 2013).

The Government expected that the rollout would lower electricity prices for consumers, increase retail competition, improve service quality and increase the efficiency of electricity suppliers. However, the rollout experienced significant problems, which provide lessons for the rollout of smart meters in other parts of the National Electricity Market (NEM).

Consumer engagement. The Victorian Auditor-General's Office (VAGO 2009, p. 13) questioned the adequacy of consultation with consumers in the process leading up to the rollout. After the rollout was in progress, a review by Deloitte (2011a, p. 9) and a broader Government review (DPI 2011) emphasised the need for customer engagement so that people were aware of the benefits of the meters. In response, the Government announced it was giving consumer and welfare groups a voice in the smart meter rollout through a new Ministerial Advisory Council (DPI 2011), as well as undertaking other measures (such as a smart meter website and a price comparison web portal).

The Government moratorium of time-based pricing. In March 2010, the Victorian Government placed a moratorium on distributors automatically reassigning customers to 'time-of-use' pricing when a smart meter was installed. The moratorium stemmed from concerns about the impacts on consumers, particularly vulnerable consumers. The moratorium added further delays to the realisation of benefits from the smart meter rollout. As Powercor and CitiPower noted, the net benefit of smart meters 'won't be achieved until time of use pricing comes in and other initiatives' (trans., p. 5). Following analysis of the customer impacts of time-based pricing, the Government has since decided that flexible pricing would be encouraged on a voluntary basis for residential consumers. The moratorium on distributors will be lifted from mid-2013 (DPI, sub. DR94, p. 9; pers. comm., 28 Feb 2013).

Excessive initial optimism. Despite initial optimism that a smart meter rollout would produce net benefits, the most recent analysis (Deloitte 2011a) found that the rollout would be likely to incur a net cost over its lifetime. Nevertheless, given that a large share of the investments was sunk, that study found that a continued rollout would pass a cost–benefit test. The Deloitte study was preceded by many other studies looking at aspects of the project (CRAIIC 2005; Futura 2009; EMCa and Strata Energy Consulting 2010; and Oakley Greenwood 2010a & 2010b), which suggested positive net benefits. It appears that costs were significantly underestimated (VAGO 2009 p. 30 and Deloitte 2011a, p. 7). For example, the Deloitte study (p. 7, found rollout costs of $2.2 billion compared with a 2010 study estimate of $1.6 billion. This is around $800

(Continued next page)

Box 10.2 **(continued)**

compared with around $600 per meter based on installing 2.9 million meters at around 2.7 million small customer points (AER 2011f, p. 16). From 2009 to 2015, the AER estimated that distributors would ultimately spend over $2 billion on the rollout (AER 2011f, p. 6). It also appears that initial benefits were over-estimated. For example, Deloitte estimated benefits of just over $2 billion, while the Futura (2009) study estimated $2.6 billion. The discrepancies do not necessarily denote error — but changing prices, more information, and judgments about included and excluded items.

Incentives for distributors to contain costs seemed to have been weak (VAGO 2009, p. 17; AER 2011f, p. 28; AER 2011g, p. 1). Victorian cost-recovery regulations for smart meters (overseen by the AER) effectively took the form of cost pass-through. This provides few incentives for cost management (albeit addressing cost uncertainty well). In 2012, the AER approved proposals by the distributors to upwardly revise their smart meter charges (2012z, p. 5), noting that the higher charges were attributable to all the distributors spending more than their approved expenditure allowances in 2011. Some distributors spent close to 120 per cent of their approved budget, which was allowed by the Victorian regulation. The Victorian Government decided in late 2011 to tighten its cost recovery regulation, including removing the cost overrun allowance and reversing the onus of proof of prudent expenditure (DPI 2011).[7] These changes will apply to the AER's future assessments of distributors' expenditures and charges.

Flaws in cost–benefit analysis. VAGO (2009) was critical of the initial study (CRAIIC 2005) that prompted the rollout of smart versus ordinary interval meters, arguing that it only considered the incremental costs and benefits, failed to reconsider the overall costs and benefits of a smart meter rollout, and did not consider implementation and technology risks. Regardless of the merits of VAGO's comments, cost–benefit analysis is challenging when it is used to inform a commitment to make a single large indivisible investment (a mandatory universal rollout) and where there are large technical uncertainties (as there were at the time).

Technology risks were not addressed sufficiently. The 2005 cost–benefit study noted the need for technology trials (CRAIIC 2005, p. 6). In 2006, the department administering the project provided advice to Government that a technology trial be conducted, but that the Government should endorse the universal rollout *before* the results of the trial. VAGO (2009, pp. 34ff) claimed that these decisions introduced 'significant risks' to the project, which was compounded by insufficient oversight of the trials, and the failure to adequately use them to inform the subsequent rollout. Since then, distribution businesses throughout the NEM have conducted many trials.

After some teething problems that put the rollout at risk, in December 2011, the Government confirmed its commitment to the smart meter rollout and introduced several changes to deliver greater benefits to households (DPI 2011). Victorian network businesses say that significant benefits are being (and will be) realised (Powercor and CitiPower, trans. p. 5).

7 The *Electricity Industry Act 2000 (Vic)* provides an ongoing basis for regulation of advanced metering infrastructure in Victoria, and empowers the Victorian Government to make cost recovery orders, though some provisions of the National Electricity Rules also apply (Victorian Government 2011). From 2016, the National Electricity Rules will be the only basis for regulating advanced metering infrastructure in Victoria.

- installation costs, with an uncoordinated rollout raising the per unit cost of installing a new meter compared with 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 rollout, 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 degree of uncertainty about costs is highlighted by international evidence. In evaluating international projects on a cost per meter basis, Rousseau (2007) reported estimates ranging between \$114 and \$740 in 2007 values, while more recently, Deloitte (2012, p. 27) reported a range between \$170 and \$900. Elsewhere, Hierzinger et al. estimated the full costs of rolling out smart meters to 50 million United Kingdom residents to be around £220 per meter or roughly A\$330 (2012, p. 88).

While accurate comparisons are difficult, it appears some international rollouts have occurred (or are occurring) at lower cost than in Victoria (although the functionality of meters is usually more limited and the associated communication systems slower and less versatile). For example, Gill (sub. DR51, p. 1) noted:[8]

> Early Smart Meter Cost Benefit Analysis undertaken by the Ministerial Council on Energy estimated the cost of a smart meter with integrated communications to be less than \$100. This estimate was based on costs for 'similar' meters deployed in both Europe and the USA. We now know that meters deployed in Victoria's advanced meter rollout were between 100 per cent and 200 per cent higher.

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 tariffs and their responsiveness to prices. As discussed in chapter 9, benefits will also vary according to the length of the transition to efficient network pricing structures, and the extent to which retailers pass these through to end-users.

10.2 Rolling out smart meters involves major challenges

The fundamental obstacle to the optimal rollout of smart meters (and many other demand management technologies) is that their economic value is only maximised

8 Dr Gill was the head of the team tasked to develop the minimum functionality specification of smart meters in Australia.

if a coherent set of regulatory and commercial arrangements are present, many beyond the control of a single agent. Removing one element can reduce or even eliminate the value of the investment in smart meters. An optimal arrangement would:

(a) require cost-reflective network charges for retailers

(b) involve retail tariffs that provide lower electricity network costs for consumers with low critical peak demands

(c) ensure that non-network solutions are a major part of the decision-making of network businesses (as opposed to the customary tendency to seek network solutions)

(d) reduce the risks from regulatory uncertainty and political decision-making, such as price moratoriums, which can undermine the economic and commercial basis for rollouts

(e) create regulatory incentive arrangements that recognise that the benefits in lowering network investment requirements extend over more than one regulatory period

(f) address the 'split incentives' problem — this problem arises because smart meters can yield cost reductions through the entire supply chain — retailers, distribution businesses, transmission network service providers, and generators. No single party is easily able to appropriate the full return from lowering costs and nor would they have strong incentives to fully disclose the magnitude of any benefits in any negotiations. A coalition of the willing is unlikely to form naturally

(g) roll out smart meters at the times and in the places that provide the greatest economic value. A smart meter is worth little if it sits in splendid isolation and its functionality is not used for the long-term benefit of consumers. Their benefits rely on being in a crowd and at the right time and place

(h) remove regulatory barriers that discourage the installation of smart meters by distribution businesses

(i) let a variety of parties make choices in this area (retailers, consumers, distribution businesses, third parties). Assigning roles in the rollout of smart meters must: avoid stifling innovative new products from retailers or third parties that can rely on smart meters as an enabling technology (for example, in home displays, apps for controlling appliances or optimising power consumption); ensure there is a capacity for multiple parties to use the information from smart meters; and allow parties other than distributors the freedom (with the consent of consumers) to install meters if that is in their commercial interest. In other words, a special case would need to be made to prevent any party from installing a meter. However, given the desirability of interoperability, there would need to be compatible standards for smart meters and appliances

(j) unbundle the contestable component of advanced metering infrastructure — such as add-on technologies — from the network charge (an issue addressed in more detail below)

(k) overcome scepticism from consumers about the value of smart meters following the difficulties experienced in Victoria.

On the face of it, this formidable list makes the prospects for a successful rollout daunting. However, many of these challenges can be sufficiently addressed so that workable (if not perfect) regulatory arrangements are feasible. The items on the 'list' are not of equal importance and some key ones are addressed in other chapters, such as:

- reforms in network and retail pricing (a and b) are feasible (chapters 11 and 12)
- cultural change in network decision-making (c) would be improved through privatisation and, in the meantime, improvements to the governance of state-owned corporations (chapter 7), and would be reinforced through reforms to reliability standards and incentive regulation to remove any biases in favour of capital expenditure (capex) (chapters 5, 15 and 16)
- putting the 'N' solidly in the NEM through a national licensing regime, the full shift of retail regulatory functions to the AER and a NEM-wide coherent approach to hardship policies (chapter 11) would weaken the capacity for political interference (d). In some respects, by tying their hands, a national approach helps state and territory governments resist political demands on them
- a capacity to capture benefits that are experienced across more than one regulatory period (e) and more than one party (f) are (partly) examined in chapter 12, though aspects are still considered in this chapter.

Accordingly, many of the pieces of the jigsaw of reforms required to implement demand management technologies are addressed elsewhere in this report. As a result, this chapter concentrates on some of the key coordination problems in achieving a coherent rollout that arise if (f) to (j) are not achieved. It also addresses some of the concerns relating to consumer receptiveness to change (k).

The starting point for unpacking the dilemmas presented by coordination of a rollout is the tensions between beneficiaries, which arise from the 'split incentives' problem.

‘Split incentives’ across market participants

The efficiencies from adopting demand management technologies occur throughout the supply chain.[9] The long-run efficiency gains appear to be greatest for distribution and generation, and are still significant for transmission, but appear to be relatively modest for retailers (Futura 2009; Oakely Greenwood 2010b; and the Commission’s own calculations). Despite the efficiency gains from avoiding excessive investment in generation, some generators face potential financial losses from demand management because it can reduce the wholesale spot price during peak periods — as the spot price forms the basis for recovery of the large (sunk) investments in generation.[10] Furthermore, depending on whether demand management simply shifts consumption to another period, or whether it results in lower overall consumption, generators may also lose unit sales of power, and higher cost peaking generators may be dispatched less often.

Accordingly, 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-incentives’ problem (an example of ‘market failure’). In the absence of successful commercial negotiations to share benefits, any individual party will tend to underinvest in demand management because they are unable to appropriate all of the benefits that flow onto other parties.

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 (Pacific Economics Group, sub. DR48, pp. 8-9). 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 New South Wales — introduced in the 1950s by the vertically integrated electricity supplier at the time — would not proceed now, despite the large savings it offers (Maltabarow 2012, p. 5).

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9 Estimates of these gains and their origins are discussed in depth in CRA (2008a, 2008b); Futura (2009); Mott Macdonald (2007, p. 47ff); and Oakley Greenwood (2010b).

10 Hedging behaviours and gentailing adds complexity to the analysis, but ultimately demand management acts effectively as new competition in the generation market, reducing returns to incumbents.

Underinvestment in smart meters and the split-incentives problem

Smart meter investments suffer acutely from the split-incentives problem (though these would also apply to other technological options, such as direct load control):

> A key economic obstacle to a market-driven rollout is the fragmentation of benefits among multiple stakeholders, which disperses investment incentives. (Schächtele and Uhlenbrock 2012, p. 1)
>
> Fragmentation across the value chain has reduced the incentive for any single player to invest in smart meter or customer applications (McKinsey 2010, p. 49)
>
> … 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. (AEMC 2012t, p. 3)

Of course, there are certain circumstances in which rollouts could still occur commercially.

- Over time, the costs of the technology may fall enough that it is worthwhile for distribution businesses to make the investments on their own account.
- At least some parties could negotiate with each other, reducing, though not eliminating, the split incentives problem. Negotiations are most likely to occur between a few parties where there is a common interest in the choice of the location of meters and the pace of their rollout. That is likely to rule out generators (who have weak incentives anyway) and to a lesser extent, retailers. The prospects for commercially negotiated arrangements are likely to be improved for transmission and distribution businesses. There are only a limited number of such businesses across the whole NEM, and even fewer at the state level, and they share a common interest in relieving pressures on the network. Grid Australia (sub. DR91, p. 23) pointed out that in New South Wales, Ausgrid and TransGrid had made ‘possibly hundreds of millions of dollars’ of savings from joint planning and integration of augmentation and replacement programs. Presumably, such joint planning could extend to demand management.

These qualifications are important because they imply that regulation may not have to play as significant a role in addressing the split incentive problem as first thought.

Nevertheless, the essential lesson from the split incentives problem is that some financial incentive will be required for any given party to roll out meters at the *optimal* time (and location). Ultimately, regardless of how the money is raised, customers will have to pay, and should do so if there is good evidence that, in the long term, net benefits of this investment will flow through to consumers.

10.3 Creating the optimal incentives for deploying demand management technologies

The best approach for smart meter investments has been widely debated in Australia and overseas, and there are many competing options.

Rollouts through edict?

One obvious way of overcoming the problem is for the government to direct a universal rollout of meters over some specified period, with the costs met as a charge on consumers' electricity bills. To the extent that smart meters achieve their goals, the consumer outlays on meters should be more than offset by subsequent savings in energy use and reduced payments for network and generation infrastructure and other operating expenses.

Some governments have taken this course, including the Victorian Government. International examples also exist.[11] In response to legal requirements to rollout meters, two European countries — Italy and Sweden — had completed full rollouts by 2012. In the United Kingdom, the Government has mandated a rollout, though current penetration rates are low. Legal requirements for universal rollouts are also in place in Finland, France, Greece, and Malta.

The usual approach under the mandated rollouts is that governments make an in-principle decision to roll out meters, with the ultimate decision based on the outcomes from cost–benefit analysis. For example, in 2009, the European Union issued a directive requiring member states to install intelligent metering systems to at least 80 per cent of customers, *where such a rollout is assessed positively*. The European Union requires member states to undertake a cost–benefit analysis. It has provided guidance on how consistent analysis should be undertaken (Giordano et al. 2012).

[11] The Commission used several sources to assess the current state of rollouts internationally, including information provided by several participants in this inquiry; Frost and Sullivan (2011); ICER (2012); Kema International (2012, pp. 22ff); Schächtele and Uhlenbrock (2012); Sentec (2012); the UK National Audit Office (2011) and, most comprehensively, Hierzinger et al. (2012).

The key advantage of a mandated rollout is that it avoids the split incentive problem. The investment decision can take account of the costs and benefits throughout the supply chain. However, it has several major deficiencies, including that:

- it may result in rollouts that, while passing a cost–benefit analysis, are not sequenced to maximise benefits. For example, it can be desirable to deploy meters first in more congested parts of the network (such as a given metropolitan area), yet governments may set timelines that do not allow efficient targeting
- it is easier to ignore the preferences of consumers where the decision is by edict. Clearly, there has been a backlash in Victoria. Moreover, in some countries, such as Netherlands, plans for a mandatory rollout were shelved following consumer opposition (Kema International 2012, p. 35). In this inquiry, several consumer groups indicated the importance of engagement with consumers and their capacity to participate in the decision-making (Public Interest Advocacy Centre, sub. DR65, p. 8; Consumer Action Law Centre, sub. DR79, p. 10) — a matter considered in greater detail in section 10.5
- the decision to rollout is made by a party that faces significant information asymmetries (compared with network businesses)
- a point-in-time cost-benefit analysis may not be appropriate where new developments over time affect the pace and location of meters (or improve the quality of the cost–benefit analysis underpinning the investment decision). For example, a legal requirement to roll out meters by a certain date loses the option value of waiting if subsequent information shows that delay is optimal. The ENA observed wryly that 'We go back to 1996 and we were all going to have smart meters within two or three years. That hasn't happened. It is evolving' (trans. p. 334).

It is notable that most countries (and states within the United States) have not mandated meter rollouts at this stage, though some are considering this. Decisions about smart meter rollouts have largely been left to utilities.

In the Commission's view, it would be premature to mandate a rapid NEM-wide rollout of smart meters at this stage, though governments could consider this at a future time if alternative models do not successfully address the split incentive problem.

A negotiated settlement orchestrated by a lead player?

Another option to facilitate investment in smart meters would be to mandate a lead business player that would then engage with other beneficiaries. 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) suggested a form of contractual agreement that apportioned the costs and benefits of smart meters across parties (AEMC 2012e).

This approach shares similarities with Littlechild's (2011a, b) 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 all the disparate commercial interests of potential beneficiaries from demand management raises issues of implementation costs and is likely to be a slow process. (As noted above, candidates for cooperation would most likely be transmission and distribution businesses.)

A 'market-based' rollout?

On the face of it, a market-based approach centred on individual consumer preferences appears highly desirable. Under that model, provision of meters would be contestable, with any party — retailers, distributors, smart meter manufacturers and third parties — able to make an offer that consumers could accept or reject. Common standards would ensure compatibility with network businesses' needs and would avoid customer lock-in to a particular suppliers' product. Having a choice on whether to invest in a smart meter and face time-based pricing resonates with most consumers. This approach was advocated by the New South Wales Independent Pricing and Regulatory Tribunal (IPART 2012d), underpinned the AEMC Power of Choice report, and was a view held by many other participants in this inquiry (box 10.3).

King (2012) puts the case well:

> This approach is simple. There is a basic meter that a consumer can have as part of their electricity connection if they want. But there is also a selection of 'approved' smart meters from competing suppliers that a consumer can pay to have installed. If you have a smart meter then, depending on its functionality, different retailers can compete for your business through the package of electricity prices that they offer to you. What are the benefits of this? First, if you don't want a smart meter (fear of radiation or Martians) then nothing changes. But if you do want to use a smart meter to manage your power consumption then you can choose the one that best suits you. In other words, consumer ownership of meters creates consumer buy-in and control.

Box 10.3 **Many participants saw competitive provision of smart meters as desirable**

Various participants (AER, sub. DR92; EnergyAustralia, sub. DR82; ERAA, sub. DR76; GDFSEA, sub. DR68; Macquarie, sub. DR54) and others favour a market-led rollout that relies on harnessing the self-interest of consumers to drive installations:

> As set out in the AER's submission to the AEMC, the AER generally supports a contestable model for rolling out interval meters, where this model can be delivered at lower cost and improve meter service offerings. The AER favours such an approach which would see the following:
>
> - Competition for the provision of meters and meter services providing impetus for innovation and economic efficiencies over time;
> - Consumer preferences determining who provides interval meters and how they should be provided — that is, having choice on the range of [distribution service provider] related services that might be bundled with the provision of a meter, or attached to the meter;
> - Arrangements developed to prevent consumer 'locking-in' concerns in relation to energy contracts and meter type (and to prevent inefficient meter churning);
> - Some consumers having the option of whether to face a cost-reflective tariff or remain on a flat tariff — at least in the short term. (AER, sub. DR92, p. 15)
>
> Competition between retailers underpins the incentives that retailers have to roll out smart meters to their customers and to deliver the range of services and products that customers want at a price they are willing to pay. (ERAA, sub DR76, p. 3)
>
> … retail competition creates incentives for retailers to install and deliver the smart meter services that customers seek in a cost-effective manner. (GDFSEA, sub DR68, p. 2)
>
> Under our proposed model, the onus will be on the retailer or [distribution service provider] service provider to elicit consumer consent to a smart meter through offering appropriate retail pricing offers and value added services. … Ultimately, it will be up to consumers to make choices based on the net benefits that end use services provide. (AEMC 2012u, pp. 68-9)
>
> The rollout 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)

Under a market-led approach, consumers would have several motivations for taking up a meter.

(i) Consumers may want to make energy savings. They could use the meter, in-home displays and other complementary technologies to discover their in-time power use, and use the information to make informed decision-making about actions to reduce power consumption. Retailers may assist in that process.

(ii) They may be able to access different billing arrangements — for example, more frequent billing or (the easier adoption of) prepaid packages.

(iii) So long as cost-reflective time-based pricing retail tariff options are given to customers (chapter 11), then non-peaky customers would tend to adopt smart meters, access (lower) time-based prices that do not include the cost of subsidising more peaky consumers and, in doing so, exit the average price pool. Those remaining on the flat average tariff would then face an average that would progressively rise (as less-peaky customers exit the average price pool) and result in them facing a higher share of the peak costs their consumption generates (AEMC 2012u, pp. 164-5).

However, there are problems in the market-based approach

Unlike many markets, there are several major and compounding deficiencies with uncoordinated action though individual choice.

Without smart meters, consumers have a poor understanding of their consumption profile and its implication for cost-reflective prices.

- Schächtele and Uhlenbrock (2012) summarised recent smart meter cost–benefit studies.[12] They found consumers had 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) identified information 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.

Similarly, retailers would not have the information to target non-peaky customers with time-based tariffs (since the information relies on the smart meters being present already). Moreover, retailers face costs in developing and marketing new tariffs to customers. The payoff from new tariffs and the marketing of them is reduced if the relevant customer group is small and only gradually increasing. PricewaterhouseCoopers considers this would materially limit retailers' incentives to roll out smart meters to consumers (PwC 2011, p. v).

Retailers have other conflicting motivations to deploy meters. On the one hand, any individual retailer may gain a competitive edge by offering some of the distinctive features and benefits associated with smart meters, which would increase, or at least retain its market share (ERAA 2012c, p. 3). In addition, smart meters would allow a retailer to move to monthly or even fortnightly billing, which could reduce working

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

capital and the risk of bad debts.[13] On the other hand, smart meters may allow consumers to reduce their energy bills, placing downward pressure on retailers' profits.

Overall, a market-based approach would be likely to lead to the relatively slow adoption of smart meters. Indeed, the Dutch Government considered that without regulation, a market-led rollout would only achieve a 30 per cent penetration rate, which was one reason for its initial (but subsequently over-turned) decision to mandate a rollout (Hierzinger et al. 2012, p. 60). In Germany, which has also adopted a market-led rollout, only 500 000 meters have been installed, though operation of a smart grid would require at least 42 million meters (Hierzinger et al. 2012, p. 44). Slower adoption rates under a market-led approach would undermine the incentives provided by price signals discussed in (iii) above. The slower the pace of adoption, the smaller would be the price differences between the standard flat tariff and a time-based tariff, reducing even further the motivation for consumers to adopt meters. Since smart meter costs are upfront investments with immediate costs, if the benefits are deferred the commercial case for rolling them out, or the case for consumers to adopt them, might evaporate.

In addition, a piecemeal rollout driven by the pace of consumer choice runs the risk of not achieving a critical mass of installations needed to realise:

- the level of demand response required to support a deferral of network investment in peak capacity
- the substantial operating efficiencies that can flow from smart meters (for networks and retailers). For example, the potential savings from reducing network constraints in a region where substantial network investments would otherwise be required would be significantly reduced with a 'patchwork' approach to their rollout. So too would the benefits of remote metering and intelligent monitoring and management of the network.

A piecemeal rollout would also be likely to lose economies of scale in meter procurement, installation, communication infrastructure and supporting IT and data management systems.

- Cost advantages accrue with installation density, making universal installation within a given area generally lower cost. (Any countervailing risks of market power that allow smart meter suppliers and/or installation contractors to inflate prices during a large-scale rollout can be limited by sensible phasing, contracting

[13] However, this is contested. Futura (2009, p. 66) considered that the costs associated with more frequent billing exceeded working capital benefits, though this may not apply with emerging technologies.

with a variety of suppliers and avoiding excessively tight mandatory completion dates).

- Some studies find that state-mandated comprehensive rollouts have lower costs per meter. One of the largest international suppliers of smart meters, Landis+Gyr, estimated that installation costs for a mass rollout would average around $40 per meter, whereas ad hoc rollouts would cost around $80 (trans. p. 32). A literature survey identified many possible economies of scale and learning from comprehensive rollouts, though also potentially higher governance costs to enforce state regulation (Schächtele and Uhlenbrock 2012, p. 281).[14] Scale economies alone would not justify intervention because scale and learning economies occur in many products. Acting on these would risk creating statutory monopolies throughout an economy. Nevertheless, scale economies are relevant amongst other considerations in choosing the best option for deploying smart meters.
- Ausgrid experiences as a metering service provider in the contestable market (smart meters) and the non-contestable metering market (non-smart meters) is that the cost of providing metering services at a contestable site is around five times that of the non-contestable site. The main reason for this disparity is the loss of economies of scale in metering reading services associated with the greater inefficiency of meter reading routes (NSW DNSPs 2013, p. 5).
- Within any region, the cost of smart meters is likely to be most efficiently incurred and coordinated by a single party, which may, if it wishes, use competitive tenders to lower costs.

Cumulatively, these considerations suggest that the uptake of smart meters under a consumer choice approach would be likely to be low and slow. This outcome significantly limits the potential for network efficiencies, particularly those from deferring investment to meet peak demand.

In theory, network businesses could attempt to stimulate the uptake of smart meters with a side payment to the customer (akin to the kinds of rebates used for direct load control air conditioners in Queensland). However:

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14 Macquarie Corporate and Asset Finance (sub. DR54, pp. 4-5) questioned these scale effects, saying that in the United Kingdom ‘we see competitive commercial organisations … installing tens of thousands of smart meters efficiently using a 'checker board' approach to scheduling and installation’. The AEMC (2012u, p. 84) said that under a market-led approach, scale economies ‘would not necessarily be lost’. However, neither provided estimates of the costs per meter under competing models. The fact that competing businesses in a market-led approach can install many meters does not reveal the efficiency of an alternative (unobserved) planned rollout model.

- unlike direct load control of air conditioners, the demand response would be uncertain
- this might produce offsetting reductions in the incentives offered by retailers and third parties if they believe they can free ride on network businesses' concessions
- it would be still likely to achieve a patchy rollout, reducing network savings, and undermining its commercial feasibility.

As detailed comprehensively by the AEMC (2012u), market-led approaches clearly have some advantages. However, in the Commission's view, smart meters are not like many other goods. In particular, they suffer from the problem that the benefits to any given consumer depend substantially on the actions of other consumers. This suggests some coordination in their adoption. Nevertheless, to the extent possible, it would be desirable not to throw the baby out with the bathwater, and to try to achieve some of the benefits of a market-based approach in a coordinated model (the goal of the Commission's preferred model — section 10.4).

A lone ranger?

In its draft report, the Commission recommended that the AER be responsible for mandating when and where distribution networks should implement smart meters — at least in the initial rollout — based on information from the businesses and using cost–benefit analysis. This would allow distributors to be the only lead business player ('the lone ranger'), with the AER required to judge the overall costs and benefits of smart meters throughout the supply chain. The approach shares some similarities with government-mandated rollouts, but is regulator-led, makes better use of information from network businesses and would be more likely to lead to the optimal sequencing of rollouts. It would maintain the option value of waiting. In many respects, the approach advocated by the Commission in the draft report was similar to that used by AEMO in relation to certain transmission investments in Victoria (chapter 16).

Despite these advantages, the Commission has reconsidered its view, prompted by fresh analysis, consideration of some of the broader issues raised by the AEMC's final Power of Choice report (2012u) and scepticism of several participants about mandated arrangements led by the AER, for example, NSW DNSPs (sub. DR85, attachment A, p. 2).

In particular, unlike investments in transmission reliability, investments in smart meters are more akin to other kinds of investments that network businesses propose in revenue determinations under incentive regulation. For example, split incentives apply to other demand management options proposed by the businesses, and yet ultimate responsibility for undertaking them still resides with the distribution businesses, not the regulator. There is an inconsistency in treating one type of demand management approach in a different way from others. Similarly, purchases of type 5 (manually-read interval) and type 6 (accumulation) meters are treated by the AER as network investments, raising the question of why a superior meter with significant network benefits would be subject to a different approach.

In that context, the Commission has shifted its position and proposed a hybrid model that involves coordination led by distribution businesses (a regulated model), but with room for other parties to innovate and customise smart meters for different consumers (a market-based model). The next section details how this model would work.

10.4 A hybrid approach that blends a market-based and regulated approach

In the Commission's view, a variant on the current regulatory arrangements applying to other capex and operating expenditure (opex) made by distribution businesses is likely to lead to better outcomes, provide scope for roles by all parties, be more flexible and require less onerous supervision than the Commission's initial proposal. To function well, the new model has several interrelated requirements.

Specify a minimum level of functionality

Minimum standards are required that allow information sharing, open access, and interoperability — such as agreed communication protocols and a capacity to link to third party peripherals and smart appliances. Minimum standards would, in effect, create a 'vanilla' smart meter, with the potential for parties to add additional functionality through linked appliances, in-home displays and other innovations. Appropriate standards would allow all parties to access the benefits available from the deployment of smart meters. Parties could also install meters with higher levels of functionality, as long as they were compatible with the standards.

The existing Rules are largely silent on any such smart meter standards.[15] However, some standards have been developed through the National Smart Metering Program,

[15] Chapter 7 of the National Electricity Rules contains a minimum functionality specification for meters, but this mostly relates to the accuracy and basic capacity for recording information for all metering types. The only significant difference between requirements for smart and other meters is that smart meters must have a capacity for electronic data transfer from the metering

which was established by the then Ministerial Council on Energy in 2008 (box 10.4).

Box 10.4 **Smart Metering Infrastructure Minimum Functionality Specification**

1. Measurement and recording
2. Remote acquisition of data and meter event logs
3. Local acquisition of meter information
4. Visible display and indicators on meter
5. Meter clock synchronisation
6. Load management through a controlled load contactor or relay
7. Supply contactor operation
8. Supply capacity control
9. Home area network using open standard
10. Quality of supply and other event recording
11. Meter loss of supply detection
12. Remote meter service checking
13. Meter settings reconfiguration
14. Software upgrades
15. Plug and play device commissioning
16. Communications and data security
17. Tamper detection
18. Interoperability for meters/devices at application layer
19. Hardware component interoperability
20. Meter communications: issuing messages and commands
21. Customer supply (safety) monitoring.

Source: NSMP (2011).

The standards followed collaboration between retailers, distribution businesses, metering providers, consumer organisations, market operators and jurisdictions.[16]

installation to the metering data services database and a capacity to store interval energy data for a period of at least 35 days.

16 Such a standard was supported by a diverse group of participants representing most stakeholders, including the Total Environment Centre (sub. DR50, p. 7); the Energy Networks Association (sub. DR71, attachment B, p. 1); Landis+Gyr (sub. DR95, p. 1); and the Energy Retailers Association of Australia (ERAA 2012c, p. 11).

However, it is important that any standard should (as far as possible) be consistent with international standards. This would avoid creating a ‘koala standard’ that could increase the cost of smart meters for the Australian market and operate as a trade barrier that denies Australia the benefit from lower cost similar meters produced for the global market (Gill, sub. DR51, p. 1; Frost and Sullivan 2011).

> As Europe prepares to install tens of millions of smart meters, Australia should position itself to benefit from resulting lower prices. This will only be possible if a review of metering standards is undertaken. (Gill, sub. DR51, p. 1)

Given there has been strong progress in this area, the Standing Council on Energy and Resources should finalise a minimum technical standard for advanced metering infrastructure, including smart meters, but should take into account the risks and costs of ‘koala’ standards.

A leading, but not exclusive, role for distributors

Under the Commission’s model, the AER would treat the capex and opex costs of ‘vanilla’ smart meters like current accumulation and non-remotely read interval meters, with their costs recovered through regulated revenue allowances (with the precise funding model discussed later). An advantage of this approach is that consumers would not face the full cost of smart meters upfront, but, as for other network assets, would pay for their cost over the life of the asset. (As discussed later, the benefits of smart meters in terms of savings in network augmentation and operational efficiencies, and greater amenity should mean that over the lifetime of the meter, these costs are more than offset by savings in consumers’ overall electricity bills.)

A clear benefit from a rollout led by distributors is their knowledge about the diverse network cost savings within its network and, consequently, its ability to tailor a rollout to best achieve those benefits (Jemena, sub. DR77, p. 18). Importantly, this includes a superior ability to forecast future constrained network regions that could benefit from a smart meter rollout. This gives them a significant informational advantage in determining the costs and benefits of any particular rollout when compared with other parties, including the AER.

Smart meters are also an intrinsic element of the so-called ‘smart grid’, whose fundamental role is real-time control of the electricity network (distribution *and* transmission) with the use of sensors, information and communication technology, with links to the customer through smart meters (Joskow 2012; Pacific Economics Group, sub. DR48, pp. 7-8; City of Sydney, sub. DR58, p. 6; Landis+Gyr, sub. DR95, p. 3). While benefitting consumers, smart grids mainly relate to the management of the network — particularly as intermittent generation grows in importance. On that basis, the network operators are again the dominant players.

Given the above, not surprisingly, the biggest sources of efficiencies relating to smart meters occur upstream of retailing, as shown in the various cost–benefit studies of smart meter rollouts, such as Deloitte (2011a) and Futura (2009). The latter found that direct benefits to retailers represented between 1.9 to 2.1 per cent of the total benefits (p. 10, p. 14). Where there are split incentives, *prime* investment decision-making would optimally lie with the party that has the most to gain, simply to reduce negotiating and coordination costs with other parties.

Distributor-led arrangements also remove the costs of the AEMC's proposed measures to address the risk of consumer 'lock in' when retailers are responsible for installing meters. Lock in occurs when a retailer charges a customer moving to another retailer an exit fee in excess of the real cost of exit (roughly the depreciated value of the smart meter). Regulations are the usual method for addressing such lock in, and balance the need for retailers to recover the costs of any meter it installs (avoiding stranded assets) and the need to avoid contracts that impose excessive exit fees (avoiding market power). However, the AEMC (2012u) has proposed a solution that avoids regulatory oversight of lock-in, but that raises its own challenges:

> The retailer would be obligated to ensure a working meter at a consumers premises (NEM compliant at a settlements point). It would also be responsible for managing and contracting with a metering coordinator (MC) to engage metering service providers on a consumer's behalf. Separating the MC role from the retailer means that a consumer can change its retailer without the need for it to change MC, thus reducing the need to replace the meter. (p. 89)

Such an arrangement creates another regulated structure in the electricity market, with rules about how parties may contract with each other (such as stipulated standard contracts).

Moreover, the AEMC's structural separation of meter coordination from retailers raises a separate issue of compensation for distributors for the lost economic value of any pre-existing meter they own (a stranded asset problem). The AEMC has proposed a set of arrangements involving exit fees to address this issue (AEMC 2012u, pp. 92-3).

The AEMC's proposals in both of the above instances would be likely to solve the problems they target, but they are problems that largely do not exist in the Commission's proposed model. They underline the fact that making a fully-fledged 'market-based' rollout work requires complex ancillary arrangements that would not usually be required in most markets. The market contemplated is very much a managed one, a relevant consideration when weighing up other managed models for rolling out meters.

While not a reason in itself, it is revealing that the dominant international model for rollouts has been distributor-led. A distributor-led arrangement was also the assessment of the (then) Ministerial Council on Energy in their 2008 evaluation of four possible scenarios for a mandated national rollout.[17]

However, unlike other infrastructure in the distribution network, smart meters would not be fenced-off like substations. Other parties should be able to access information collected by meters (but constrained by privacy provisions). They should also have open access to the meters for peripheral devices (subject to agreement with the customer) and could reach commercial agreements with network businesses to install meters, or if they wish, to invest in network compatible networks in their own right. For example, a retailer wishing to compete for customers by offering a meter with greater functionality and with an associated set of peripherals could negotiate with the distribution business to pay the incremental cost of the higher-functioning meter. Unbundling metering charges from other network charges to retailers (as advocated by GDF Suez, sub. DR68) would provide the transparency needed to encourage such commercial negotiations.

The issue of exit fees for peripherals installed by a retailer would be solved without any intermediary, and would draw on the generic Australian Consumer Law's provisions against unfair contracts (as is the case, for example, with mobile phone plans) were a retailer to set excessive exit fees.

Recovering prudent costs

Network businesses on the whole were supportive of the rollout of smart meters by distributors, but noted that this was only so long as the business case was satisfied and all relevant costs were accounted for (ENA, sub. DR71). By treating 'vanilla' smart meters as part of the distribution network (similar to poles, wires and substations), the implications is that distributors could recoup the costs of rollouts in ways analogous to other network costs.

The AER could compensate distribution businesses for such smart meter rollouts using two quite distinct approaches.

17 The other three scenarios examined were a retailer-led rollout, a centralised communications rollout and a direct load control rollout without smart meters.

Rate of return regulation provides certainty, but weak incentives

Under the first approach, the AER would approve a rate of return on an agreed rollout of meters, with no or limited potential for the distribution business to amend its plans (effectively 'rate of return' regulation). This would ensure that the rollout occurred as set out in the regulatory proposal and insulate the distribution business from any cost risks associated with rollouts (thereby providing certainty for the business about an adequate return).[18] Most importantly, it would directly address the split incentives problem, because the distribution business would be adequately rewarded regardless of where the benefits accrue throughout the supply chain. However, this approach would effectively replicate many of the features of the Commission's draft proposal, with its disadvantages. In particular, the distribution business would have no incentive to seek other non-smart meter solutions to demand management. And unless competitive tendering for smart meters were required, nor would it provide incentives to contain the costs of rollouts.

An adapted form of incentive regulation is likely to perform better

Under the second approach, an adapted form of current incentive regulations would be used to recoup the cost of their investment in smart meters. The AER would make an ex ante determination of an aggregate revenue allowance based on an initial building block proposal by the business, which would include any demand management options, such as smart meters and direct load control. The AER would approve a revenue allowance for the total capex and opex using the approaches set out in the Rules (chapter 5). For example, it could question the costs and prudency of any proposed spending on smart meters, and, combined with its analysis of other capex and opex proposals by the business, it could reject, accept or modify the total expenditure allowance depending on its findings. However, in keeping with incentive regulation, it would not require a distribution business to actually make the specific investments set down in its proposal, whether they be smart meters, substations or pole replacements.

[18] As an illustration of the uncertainties with the regulatory return of smart meter costs, the AER deemed that in Victoria, SP AusNet's rollout 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). The decision went to the Australian Competition Tribunal for merits review, which remitted some matters back to the AER for consideration.

The business would have the freedom to make its own capex and opex choices. It could decide to roll out more or fewer smart meters than it projected in its original regulatory proposal, find implementation savings, seek purchasing discounts, and take account of changing circumstances. The business would take any savings as profits. This approach would mean that any rollout would meet a *commercial* cost-benefit criterion, at least to the distributor.

However, its Achilles' heel is that, absent other incentives, it would lead to underinvestment because:

- the business might not be able to appropriate a sufficient share of the network savings that occur in subsequent regulatory periods. As noted by PricewaterhouseCoopers:

  > … current incentive schemes do not deal well with projects that have an upfront cost in return for potential future benefit (this is because incentive schemes reward or penalise distributors for any divergence between forecast and actual expenditure over a regulatory period, and so benefits created for future regulatory periods are omitted). (PwC 2011, p. v)

- returns to other parties would not be included in the commercial decision-making of the distribution business.

In relation to the former, this issue is not unique to smart meters, and, where the issue is sufficiently large to impact investment decisions, has a solution. In approving revenue determinations, the AER must, to some extent, track individual projects between regulatory periods, taking this into account in its determinations. A similar process is needed for the efficient operation of the Efficiency Benefits Sharing Scheme (chapter 5).

In relation to the latter, the existing incentive regulatory regime includes a scheme intended to address some of the barriers to demand management — the Demand Management and Embedded Generation Connection Incentive Scheme. Some see it as deficient. Ausgrid, for example, has claimed that it could not appropriate the benefits of demand management for transmission or wholesale generation costs, and that these benefits would be eight times greater than those recognised under the current regulatory framework (Maltabarow 2012, p. 4). The Commission examines that scheme in greater detail in chapter 12, but the critical point is that complementary reforms to such incentives would be required to create optimal incentives for rollouts.

It is notable that, notwithstanding its view that a market-led rollout is desirable, the AEMC has recognised the benefits of a smart meter rollout similar to that proposed by the Commission above. It has proposed that this option would sit alongside the market-based approach:

> We have proposed that network businesses would be able to do targeted roll outs of smart meters in a defined area subject to AER approval as part of the DNSPs regulatory determination. (AEMC 2012u, p. 94)

The relevance of the Regulatory Investment Test for Distribution

The recent introduction of a Regulatory Investment Test for Distribution (RIT-D) in the Rules (s. 5.17) may, in cases involving large-scale smart meter rollouts, also assist in drawing attention to, and quantifying, the wider benefits of smart meters.[19] The RIT-D requires distribution businesses making integrated investment projects of more than $5 million to undertake a cost–benefit test. This would have several implications for the rollout of smart meters.

- One of the aspects of the RIT-D is the consideration of other options, which, in the case of a conventional network augmentation, could include smart metering and direct load control as other ways of managing load.
- The RIT-D would apply to any large-scale rollout of meters in its own right.[20] This would require publication of a cost–benefit test, but as in the current Regulatory Investment Test for Transmission (RIT-T), there is no requirement for the AER to approve the outcome of the test. As a result, there is inevitably scope for a network business to influence the outcome towards their preferred project.

A key issue is whether a tougher test than the present RIT-D should apply. The Commission has recommended that large-scale transmission investments would be treated in a manner similar to a contingent project and be subject to a mini-revenue determination and a cost–benefit test for the specific project (with the detail spelt out in chapter 17). In principle, the same approach could be adopted for distribution investments.

However, there are some complexities in adopting the Commission's proposed RIT-T/contingent project approach as the model for large-scale investment by a

[19] In that respect, the recent comprehensive guidelines for cost–benefit analysis of smart meters in the European Union would provide a useful framework (Giordano et al. 2012).

[20] This takes as given that the Rules have been changed along the lines of recommendation 10.3 (thus removing the constraints imposed by schedule 7.2.3 of the Rules). Moreover, the Commission has judged that the various exemptions from a RIT-D (as set out in schedule 5.17.3 of the Rules) would not apply to large-scale smart meter rollouts. The guidelines for the application of the RIT-D currently being developed by the AER should make this clear, or if necessary, the Rules changed to ensure that large-scale smart metering rollouts would not be exempt.

distribution business generally, or specifically for large-scale investments applying only to smart meters.

- The latter would involve a separate incentive regulatory regime for smart meter rollouts alone. Applying the text would entail significant complexities in addressing the large degree of substitutability between smart meter rollouts and other demand management options for distribution businesses (such as direct load control). These substitution possibilities are likely to be more substantial than those applying between lumpy transmission assets and other expenditures by transmission network service providers.
- AEMO can provide impartial and informed advice on transmission assets, but there is no obvious party to do this for smart meter rollouts.
- From a pragmatic perspective, it may be difficult for the regulator to determine whether a rollout of meters represents a single integrated investment, or a series of separate sequenced regionally-based investments. (This is unlike large lumpy assets like zone substations). Unless there is clarity on this point, it would be difficult to test whether the deployment of demand management technologies would meet a suitable threshold test for consideration. (By way of example, $38 million is the threshold for transmission assets under the Commission's RIT-T proposal.)
- In practice, the Commission envisages a smart meter rollout process that would typically mean that even integrated rollouts in a region — say to 10 000 households — would fall well under a threshold like that applying to the Commission's proposed RIT-T/contingent project approach. As an illustration, Deloitte (2011a) calculated that the total costs of deploying meters under the present Victorian rollout were around $800 a meter. This includes some fixed costs, such as IT systems. Nevertheless, if that average value applied, a rollout in a given area to 10 000 residences would cost around $8 million, well under the Commission's proposed $38 million RIT-T/contingent project threshold. Accordingly, there may be few occasions in which a tougher RIT-D approach of the kind described above would actually be triggered.

Accordingly, at this stage the Commission does not support any extension of the RIT/contingent project approach to distribution investments, whether for smart meters alone or especially for all large-scale distributor investments. However, that option could be re-considered depending on the outcomes from adopting the Commission's recommendations for large-scale transmission projects and on the pattern of rollouts of smart meters. Regardless, any such approach should only apply to large-scale rollouts.

The current RIT-D would still have value by making it transparent and clear to customers and other stakeholders whether the rollouts were likely to provide overall network savings (with the benefits of reducing pressures on electricity bills). The AEMC also considered that the RIT-D would serve a useful purpose as a cost-benefit test (2012u, p. 94).

However, in its current form, the RIT-D has at least one clear deficiency. For most investments, the RIT-D is intended to clarify (but not require) that a proposed investment passes a cost–benefit test, and that no other options are preferred. The exception is that for reliability-related investments, the test identifies the option that maximises the present value of the net economic benefit, which, as the Rules explicitly acknowledge, could be negative (clauses 5.17.1(b) and 5.17.1(c)(9)(v) of the Rules). This is contrary to an incentive framework for reliability as spelt out in chapter 15, which should induce distribution businesses to only undertake reliability investments that meet a cost–benefit test. The exception for reliability-related investments should be removed from the Rules. It is likely that the main impacts of such a change would not relate to investments in smart meters, though these are widely regarded as having significant reliability benefits.[21] Irrespective of this, the Rules should be amended so that the RIT-D becomes a genuine cost–benefit test, with benefits exceeding costs. This is consistent with the Commission's recommendation in relation to the Regulatory Investment Test for Transmission (recommendation 17.4).

An additional concern about the RIT-D is the threshold that triggers it, and the potential risk that a set of separate, but very similar investments would each be subject to the test — with the compliance costs that this entails. This could apply to many distribution investments, but is especially relevant to smart meter rollouts, as the Commission envisages that these would be sequenced and localised. Some regional rollouts would be extensive — with costs well over $5 million dollars — and justifiably subject to the RIT-D process. However, that would not always be true. Undertaking RIT-Ds for each of a succession of modestly-sized rollouts that just exceeded the current threshold appears to be unnecessary. This is particularly so because, under the Commission's approach, a distribution business that proposed a rollout of smart meters as part of its revenue proposal for the coming regulatory period would still have to justify the prudency of its proposal to the AER (as it

21 These benefits can arise by relieving peak capacity constraints that would otherwise have led to reduced reliability, improving the performance of the grid, improved fault-detection, and their importance to the 'smart grid' (which in its own right has significant advantages for network reliability). The importance of advanced metering infrastructure in these areas has been noted by the AEMC (2012u, p. 3, p. 122); CRA (2008a, p. 75); Futura (2011, p. 32); Joskow (2012); and Kema International (2012, p. 52).

would for other investments under current arrangements). The added benefits of a full RIT-D for each component of a larger-scale rollout are unlikely to be high.

A higher threshold (or the scope for exemptions in these cases) would resolve this problem. The appropriate threshold for the RIT-D and the scope for widened exemptions should be assessed if, after some experience with the test, it appears to raise compliance costs by more than its value in improving transparency of the investment process.

Amend the Rules so that network businesses face no biases towards accumulation and non-remotely read interval meters

The current Rules create incentives for distribution businesses to install manually read meters instead of smart meters, even when replacing old meters or installing meters in new dwellings (box 10.5).

In practice, this means retailers have the primary responsibility for remotely-read interval meters (smart meters), and distribution businesses the exclusive responsibility for manually read meters. As noted by the AEMC:

> … LNSPs [local distribution network service providers] have the incentive to install manually read interval meters for which they are exclusively responsible for providing (ie. they are the Responsible Person). If a LNSP wanted to install a remotely read metering installation, which may be cheaper to read and lead to lower long term costs, the retailer would be responsible for providing the metering installation unless it agreed to give this responsibility to the LNSP. Under the current arrangements, the LNSP cannot seek AER approval for expenditure on a remotely read interval meter (type 4 metering installation) as these meters are a contestable service. (AEMC 2012d, pp. 12-13)

The current distinction in the Rules regarding the provision of metering services based upon the type of meter should be removed, so that network businesses would be able to install remotely read smart meters and access the demand response needed to defer network investment in peak capacity.[22] It is hard to see how the current regulations that induce distributors to install what in most circumstances would be an inefficient metering arrangement is consistent with the National Electricity Objective and the long-term interests of consumers.

22 The AEMC has recommended this change (2012u, p. 106).

Box 10.5 **Current Rules on who installs what meter**

When contestability was introduced into the NEM, four market segments were envisaged: networks, generation, retailing and metering, with only the first regarded as having natural monopoly characteristics. The implication was that the other segments could be supplied efficiently through competitive markets, so that economic regulation was not required for those segments. In some cases — most notably retailing and large-scale generation — networks have now been fully vertically separated. In others, such as metering and distributed generation, networks can offer contestable services, but are subject to restrictions to address the risk that they might gain unfair commercial advantages in contestable markets (for example, by cross-subsidising such services or using information from a regulated activity for the benefit of a contestable one — Ausgrid 2012d, p. 2).

In relation to metering, these concerns about residual market power and the contestable supply of metering have been expressed in various ways.

- State and territory regulators developed ring-fencing guidelines for their network businesses. Many of these guidelines relate to ring fencing of retailing from distribution, and do not specify smart meters or other emerging technologies as expressly ring-fenced (AER 2012e, p. 6). The AER is currently seeking to create NEM-wide ring-fencing guidelines.
- Distribution businesses are able to exclusively supply manually-read Type 5 and 6 meters, with recoupment of costs through regulated revenues. (Distribution businesses are the 'responsible person' under s. 7.2.3 of the Rules v.54.) Such meters do not have natural monopoly characteristics, yet are still regulated assets that can be part of the regulated asset base of a distribution business (Kema Australia 2013, pp. 59-60)
- However, a distribution business is the responsible person for Type 1 to 4 meters (smart meters) only if a market participant:
  - has accepted the offer of a distribution business to fulfil that role or
  - requests that the distribution business fulfil that role.

As smart metering is classified as a contestable service, distribution businesses cannot seek regulatory approval for smart metering expenditure, which reduces their incentive to invest in anything other than manually-read meters. Consequently, they would typically replace an old meter with a Type 5 or 6 meter (and install such meters in new premises).

Much of the discussion on smart metering is underpinned by the notion that the only relevant consideration is the presence or absence of natural monopoly (understandably since this was the focus of market delineation at the commencement of the NEM). However, market failures — most notably in coordination — can also justify a privileged role for a single party to roll out 'vanilla' smart meters.

Sources: AER (2012e); Ausgrid (2012d); Kema Australia (2013, pp. 106ff); Metropolis (2012, pp. 3-4, 11).

The links to retail price regulation

A smart meter rollout provides an efficient and flexible mechanism for introducing time-based retail charges (with greater versatility than non-remotely read type 5 interval meters). The full benefits of smart meters would require that state and territory governments remove retail price regulation (chapter 12).

Nevertheless, it would be still be possible to initiate the Commission's reforms for smart meters ahead of the removal of price regulation. The outcome would be a slower (and sub-optimal) diffusion of smart meters. However, under incentive regulation, a distribution business would only install meters if it expected that this would minimise its costs (so as to maximise its revenue allowance).

For example, a business might roll out meters where it gained sufficient benefits from:

- network management
- remote meter reading
- increasing the use of smart appliances so as to defer network investment. This would not require that retailers set cost-reflective tariffs, but could be encouraged through direct incentives from distribution businesses.

Accordingly, the Standing Council on Energy and Resources should proceed with the immediate implementation of the Commission's model for rolling out smart meters so that the regulatory arrangements for taking advantage of price deregulation would be in place.

10.5 There must be a role for other parties

Retailers and third parties

One of the main reasons for rolling out smart meters is to facilitate time-based pricing and so elicit a demand response from consumers. Under the Commission's proposals, retailers would face cost-reflective network charges. Retailers could then use the information provided by meters to produce retail tariffs for those customers who currently provide cross-subsidies to peaky consumers and those peaky users who may respond to time-based charges. Retailers could make money from clever tariff development and market segmentation, with offers that were appealing to certain consumers. The imperative would be to ensure retailers had access to the relevant smart meter information needed to achieve that.

Retailers (and other third parties) would also be able to develop products — whether it was advice on energy efficiency, direct load control, phone apps and in-home displays — that drew on the functionality of the smart meter. Retailers would be in the best position to undertake such a role because of their direct relationship with an existing or prospective customer. As the Energy Retailers Association of Australia stated, 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)

The fundamental point is that a basic smart meter is unlikely to excite much interest with a consumer, as opposed to the view expressed by King (2012) that they are akin to consumer electronic devices.[23] In contrast, the most attractive feature of the new technology is likely to be the potential for consumers to reduce their overall electricity bills by utilising the add-on capabilities of smart meters, better tariff classes and usefully distilled information on electricity usage patterns. These are separable from the meters themselves. While this part of the market should be fully contestable, innovation in these areas is likely to be driven by competing retailers and equipment manufacturers.

An important driver of competition in the contestable part of the market is separate billing of any other products and services that complement the 'vanilla' smart meter — such as an in-home display. In that way, consumers would be able to compare the prices of the various offers by electricity retailers, distribution businesses, appliance retailers and others. In the absence of such separate billing, a retailer or distributor might simply conceal the cost of an add-on in a more generic fixed charge, undermining competition.

However, the charges for the 'vanilla' meters should not appear as a separate billing item because the meters are likely to reduce other network and energy costs by more than the cost of the meters (as discussed later), without these offsetting savings being visible to the consumer.[24] But, given other electricity cost pressures, overall electricity bills would not fall by as much as the savings realised from smart meters. In this instance, with separate billing, consumers would see the addition of a separately itemised metering charge to their bills, but would not see the savings, which would be subsumed into the accompanying non-itemised charges. Were those

[23] Moreover, unlike most consumer electronic devices, smart meters have a relatively long life and it would be costly to replace them quickly. This is not likely to be true for some peripherals and other add-ons (for example, software that helps households manage their energy use).

[24] Currently, there is no separately itemised charge for a type 5 or 6 meter.

other charges to rise, the consumer would observe an overall electricity bill that would not go down by the amount of the metering charge (or might even rise). To give a tangible example, suppose that a smart meter charge of $100 per year were added to people's bills, and that the smart meter facilitated a saving in the rest of the electricity bill of $300 (or a net saving of $200). However, if other (unrelated) electricity charges were to increase by $300 due to other cost pressures, a consumer would only see a new charge for the smart meter and no apparent saving, and falsely (but understandably) assume that the only reason their bill had increased was due to the smart meter.

Pricing transparency is intended to assist, not confuse customers — so that 'vanilla' metering costs should be bundled with other network costs. Nevertheless even with bundled charges, a major role for the AER would be to ensure that there are genuinely offsetting benefits, and communicate this to consumers so they can be satisfied that smart meters are not adding to their overall electricity costs.

The role of the consumer

Other than at the street level, consumers are generally not aware of the investments made by network businesses. Planning issues aside, most would not consider that they had a major role in deciding when a new substation should be built or its technical specifications. However, this does not hold for smart meters as:

- they are attached to the premises of the household
- they provide a potential role for consumer decision-making about power usage and billing
- they collect (and make available) much more information about household electricity consumption than old meters, raising concerns about privacy and hacking. As an indicator of their importance, privacy concerns dominated the public and consumer advocacy debate about a mandated smart meter rollout in the Netherlands, leading to the decision to have a voluntary rollout (Hierzinger et al. 2012, p. 60). (As discussed below, these problems can be resolved)
- there are misperceptions about their safety in terms of fires and electromagnetic radiation (Deloitte 2011a, pp. 52-54, p. 104)
- the benefits can be hard to explain, except for customers who have elected to have solar PV units installed and see the smart meter as an essential component of getting paid for the power they export to the grid. The Deloitte study found that in Victoria there was 'very limited understanding in the general population on the reasons for installing smart meters and what they are to be used for' (2011a, p. 54). Research undertaken for Smart Grid Australia (2012, p. 34)

found that 38 per cent of Australians had a negative view about the introduction of smart meters and nearly 45 per cent of Queensland and New South Wales respondents had not even heard of them (compared with 6 per cent of Victorians). In Victoria, 25 per cent of consumers had *very* unfavourable views about the introduction of smart meters and 60 per cent of respondents had unfavourable views. Overwhelmingly, consumers thought that the energy industry should be responsible for educating them about the benefits, with retailers and distributors seen as the most reliable source of information (Smart Grid Australia 2012, pp. 35-6)

- while people accept that billing for electricity use requires metering, there seems to be much less awareness that electricity costs vary significantly during critical peak periods, and that the only efficient and equitable way of measuring and charging for that use is through some kind of interval meter. Were supermarket pricing like electricity pricing, there would be no individual prices on any supermarket item and only one total bill when the shopper paid at the checkout.[25] What seems to be absurd in the grocery market is now seen as normal in electricity, and represents a barrier to the adoption of smart meters.

In that context, many consumers are likely to resist the rollout of a technology for which they would be obliged to pay, but that has uncertain future benefits for them.

This problem is well recognised in Australia and overseas.[26] This emphasises the importance of retailer and third party involvement, and of broad education and marketing, including:

- informing consumers about the real costs imposed by just a few hours of peak demand. People are sometimes willing to change their behaviour if they are aware of the broader public (and private) benefits of curtailing peak demand, as shown by consumers' responses to entreaties to conserve water during the recent drought
- indicating the general savings to network operations, and providing estimates of the bill savings these would entail, especially to consumers who are not large users of electricity at peak times, without overselling the magnitude or the timing of those savings (a point emphasised by Smart Grid Australia 2012, p. 7). The results of RIT-Ds — in a digestible form — should assist this

25 Ehrhardt-Martinez et al. (2010, p. 1) citing a previous study.

26 For example, the AEMC (2012u, pp. 24-50) provides a comprehensive analysis in the Australian context. Ehrhardt-Martinez et al. (2010) examine international evidence about the magnitude of electricity savings from the use of smart meters, and how these depend crucially on the nature of consumer engagement.

- 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
- addressing safety and privacy concerns. Following the consumer backlash to smart metering in Victoria, the Victorian Government has tried to address consumers' concerns by better communicating the statutory protections of people's privacy. As noted by DPI (2013b), energy businesses in Australia must comply with the Federal Privacy Act (1988), which includes the National Privacy Principles. These Principles set clear restrictions on the use, disclosure and storage of personal information. The collection, use and disclosure of metering data by electricity companies is also subject to strict confidentiality rules set out by the Essential Services Commission's licensing framework and the National Electricity Rules. A national licensing regime (discussed in chapter 11) would ensure that uniform privacy provisions were in place across the entire NEM, avoiding state-specific provisions. The Public Interest Advocacy Centre (PIAC 2013, p. 7) argued that a consumer information campaign would help address consumer concerns about privacy and security issues
- indicating that decisions about using the add-on capabilities of smart meters would be subject to consent by the consumer
- 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).

Moreover, if the AER is performing well in its regulatory responsibilities, then the revenue allowances it provides to network businesses should take account of the network (and upstream) savings from demand management. Accordingly, electricity bills for the average consumer should fall compared with the counterfactual. Given its role in regulatory determinations (and in the ancillary incentive schemes that promote demand management), and its improved benchmarking capabilities, the AER is in the best position to quantify these net benefits, and to make the information publicly available. A smart meter rollout that raises average electricity bills above counterfactual levels will have failed consumers.[27]

A collective funding principle to pay for smart meters

Ideally, within a geographic region, a rollout of 'vanilla' smart meters would be financed through a fixed charge included in network tariffs to retailers. The asset life of meters is around 15 years, while the communication module within the meter has an expected life of around seven years. Accordingly, the annual charge would only be a share of the total meter's full price.

The savings from smart meters (and the associated effects of cost-reflective pricing) stem primarily from the reduction in network costs to meet peak demand, from savings in general network operations and management, and reductions in energy consumption (chapter 9). While, on average these savings are likely to offset meter charges, these savings are not equivalent for all consumers.

Trials find that low-income households tend to benefit from time-dependent charges. 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. Further, if they respond to price signals, 92 per cent of low income households would be better off (Faruqui 2010). (Nevertheless, it would be important to provide information to lower-income consumers in particular so that they are aware of the likely effects of time-based pricing — and can make prudent judgments about their energy using practices.)

However, it is important to distinguish between low-income consumers and low power-usage consumers. Low total consumption does not necessarily equate with low use at critical peak times. The best available evidence is from interval meter data (table 10.1), which 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. Nevertheless, of the people who have low off-peak usage (of 0–4 kWh per off peak period per day), just over 10 per cent had high peak usage (of 10+ kWh per peak period per day).

27 The test should be whether the present value of the savings in electricity bills over the life of the meter exceed the costs to customers from funding the rollout and ongoing operation of meters. In the shorter-term, customers may pay now to save later, which is one reason why it can be difficult to explain the benefits.

Accordingly, there may be equity concerns for disadvantaged groups who consume power at peak times.

In addition, while smart meters should have offsetting *long-run* savings in network costs and energy bills, these savings are not necessarily realised immediately but are spread over several regulatory periods. Depending on how the AER addresses this inter-temporal issue in its revenue determinations, the fixed metering charges may initially be higher than the immediate network savings. Some consumers (particularly those on low incomes, who tend to spend a greater share of their income on electricity — chapter 2) may find these initially higher fixed metering costs difficult to meet.

Given these concerns, state and territory governments could develop criteria for assistance to low income households for the cost of smart meter fixed charges and time-based charging. It would be desirable that such criteria be consistent, at least, across the NEM and possibly also consistent across utility services more broadly (recommendation 11.8).

Table 10.1 **Relation between peak and off-peak consumption**[a]

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

Peak period	Off-peak period: *Low usage (0–4 kWh off peak use per day*	Off-peak period: *Medium usage (5–9 kWh off peak use per day)*	Off-peak period: *High usage (10+ kWh off peak use per day)*
High usage (10+ kWh peak use per day)	3	18	44
Medium usage (5–9 kWh peak use per day)	7	10	1
Low usage (0–4 kWh peak use per day)	16	1	0.1

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 7 am to 10 pm on weekdays. To illustrate how to read the diagram, 3 per cent of households have high peak use and low off-peak use.

Data source: Simshauser (2012).

Would all consumers get smart meters?

The supply-side efficiencies of smart meters rely on high rates of penetration. However, since network businesses are likely to be the prime decision-maker under the Commission's proposal, they may decide that it is not economic to install smart meters in a given location. For example, data from sensors on street level transformers might show little peak demand in a given area, or that the network savings might be too small if the network has recently been augmented. This is a desirable outcome from an efficiency perspective. It would not prevent a retailer or other party installing a meter at the request of any of the relevant consumers concerned (potentially accompanied by commercial agreements with a distribution business to pay some of the costs).

Beyond these cases, there are few grounds for providing exemptions for the installation of smart meters. Targeted relief for the costs of installation for vulnerable consumers is likely to be more efficient than failing to install meters (as discussed above). 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 meter reads could be in the order of $80–$200 per meter, which would significantly contribute towards the cost of a new smart meter. Indeed, in some states in the United States, utilities are able to bill customers who opt out of smart meters with an additional charge reflecting these costs (though some states do not permit any opt outs). In California, the opt-out charge was an initial US$75 fee and a monthly bill of US$10 (Cho 2012).

In conclusion … smart meter rollouts need to be supported by consumer engagement

In conclusion, the importance of involving consumers in any rollout, associated pricing and other aspects of the regulatory process is critical, and would involve both consultation and information provision, and some championing by governments (as occurred in the case of water conservation). Failure to do this could lead to a consumer reaction that undermines the case for investment in technologies and stalls progress towards pricing changes that will benefit consumers over the longer term. Chapter 11 discusses the engagement process for pricing reform — of which a smart meter rollout is a significant prerequisite. More generally, chapter 21 proposes reforms that would give consumers much more power in the regulatory process.

10.6 Control of 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 purposes by multiple market participants. As discussed above, smart meters can be used to collect valuable information about household consumption patterns. The price responsiveness of consumers could also be gauged with add-on technologies to enable retailers to communicate real-time prices to end-users. 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 10.2). Under a distributor-led rollout, the communications infrastructure would be controlled and maintained by distributors, since it closely 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.

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)

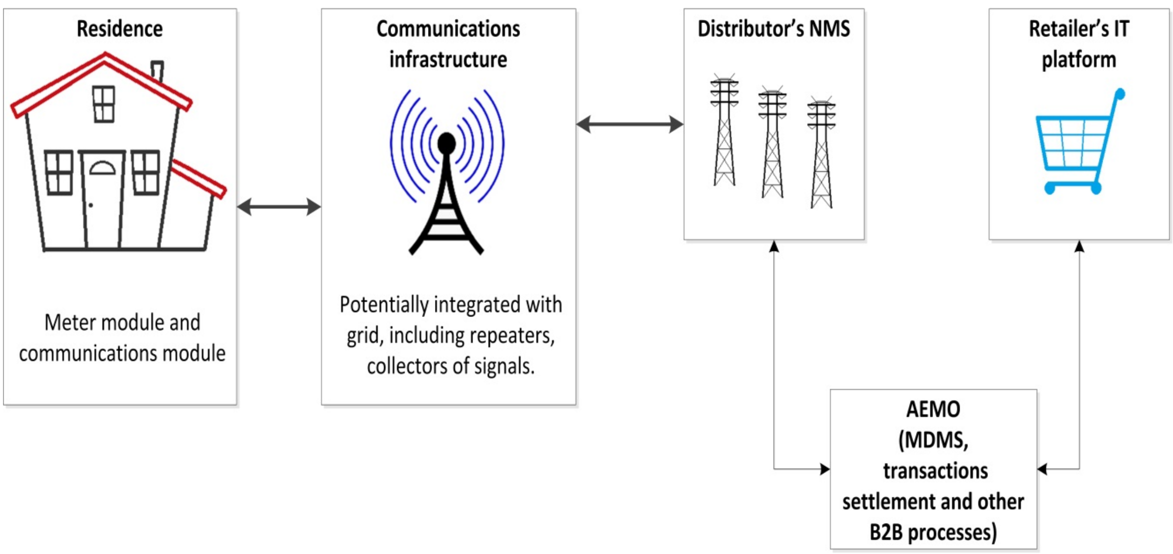
– retailers (to manage both network and wholesale market events, billing to their customers, and deliver demand management services, such as direct load control, on behalf of their customers)

– 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 rollout 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.

Figure 10.2 **The smart meter platform**



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. Equally, however, an alternative where each distributor developed its 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 National Electricity Rules (and National Energy Customer Framework) should provide clear guidance about which parties are approved to access data. Currently, the Rules assume 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 give retailers 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.

10.7 Direct load as an alternative or complementary option

Direct load control can act as a complement or substitute for smart meters.

In the absence of smart meters, direct load control technologies probably offer the most practical option to implement peak demand management.[28] Indeed, NSW DNSPs (sub. DR85, p. 2) said that direct load control has a key role to play in managing peak demand for electricity distribution networks. 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.

Where there are already smart meters and cost-reflective pricing, direct load control may act as a complement because it 'locks-in' power savings at critical peak periods, without a household having to make choices about their power use at these times. (The corollary is that it reduces the risks of 'bill shock' if a person forgets to reduce their power use during a critical period.)

In either case, direct load control allows a network provider to predictably 'clip' household demand during peak periods. Predictability is important because it means that the network businesses can be certain that they can reduce peak load capacity requirements without reliability problems (figure 10.3).

However, in the absence of cost-reflective pricing, such schemes require the use of incentive payments to ensure households realise some benefits from reducing their peak consumption.[29]

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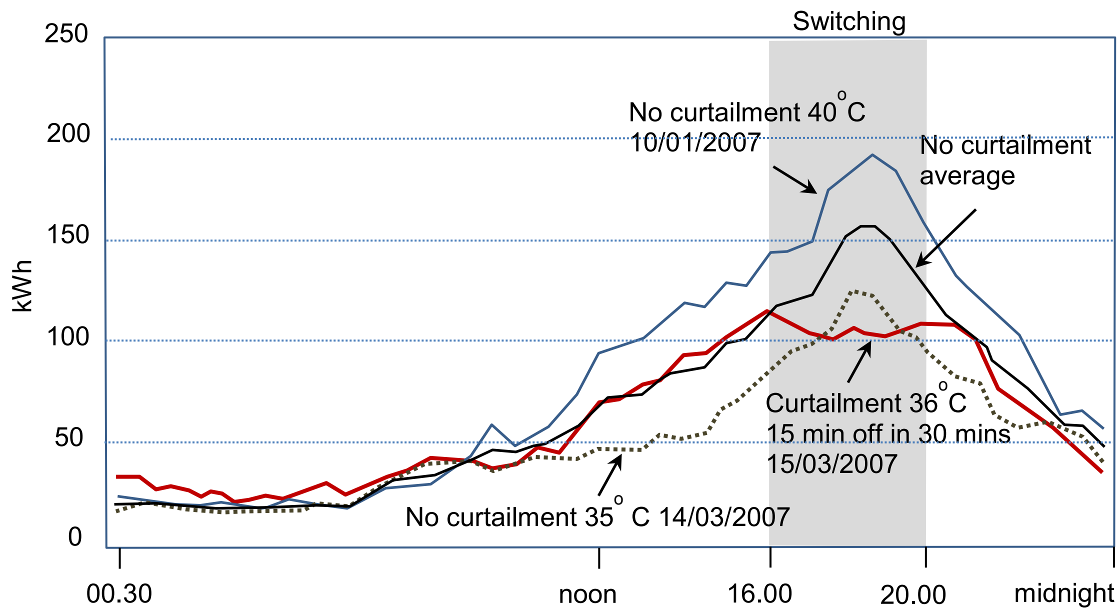
[28] Demand limiting switches are a similar technology approach, but are not remotely controlled by a utility provider. They require the end-user to pre-program decisions about what appliances to switch off during peak periods in order to stay within a nominated consumption limit. This approach requires 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 cycled off) and can secure a more reliable demand response.

[29] 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 with a price mechanism, incentive payments are a blunt and inefficient instrument to reduce peak

Figure 10.3 '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).

Most direct load trials have focused on incentives to manage 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, 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, direct load control does not involve completely switching off air conditioners. In some trials, the fan in the unit continues to operate, but the compressor of the air conditioner is cycled on and off remotely, such that the unit does not operate for 7.5 to 15 minutes out of every half hour window. However, in the recent application of direct load control of air conditioners, the energy use of the unit is limited, allowing the compressor and the de-humidifier to always remain on, increasing consumer comfort. For example, in South-East Queensland, Energex provides incentives for households to install so-called PeakSmart compatible air conditioners (and letting the network use them to control peak demand). A small device installed in PeakSmart air conditioners receives remote signals that cap the energy consumption of the air conditioners to 50 or 75 per cent of their usual energy use when the electricity network reaches peak demand. Households receive a

use. Moreover, financing such payments through a higher average consumption price can distort pricing efficiency or lead to distributional concerns (chapter 11).

one-off incentive of between $250 and $500 per air conditioning system, depending on its features (pers. com. Energex and Energex 2013).

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 will be a friend to direct load control

Technological change will aid the management of electricity demand through remote control of appliances. While adopting new technologies can be costly, the real cost can fall dramatically as scale economies result from mainstream take-up. The horizon of potential automated demand management solutions is large and rapidly developing. For example, mobile phone apps can already remotely control some compatible appliances (Landis+Gyr 2012; Owano 2012). Peak load pricing and the diffusion of smart meters would accelerate such innovation.

Should direct load control capability be mandated?

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). There is a potential rationale for compulsion because many appliances are long-lived and consumers may fail to consider the future benefits of direct load control when making initial purchases. Retrofitting is very costly, while building in a capacity at manufacture is low cost.[30] Moreover, a standard avoids the development of multiple, potentially incompatible technologies and could encourage the more rapid diffusion of direct load control.

However, the Commission is not convinced that mandated standards are justified or will be necessary. Currently, there is a limited motivation for consumers to take up the technology. This would be likely to change if there were greater financial incentives to do so, either through payments, such as that of Energex, or through avoided higher bills if critical peak pricing were introduced. Not all air conditioning

30 For example, to retrofit an air conditioner to enable direct load control requires electrical re-wiring, and could cost around $1500 (EnergyAustralia and Transgrid 2009). However, with an appliance that was originally designed and manufactured to incorporate a demand response capability, direct load control is possible for only a fraction of that cost. Wilkenfeld (2011b, p. 17) estimates that the interface cost per appliance would be around $10 per appliance.

brands would need to be compatible with direct load control technologies to achieve change. By August 2011, two 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 six were compatible, subject to the addition of an extra part (Wilkenfeld 2011b, p. 9). The Equipment Energy Efficiency Committee noted that the manufacturers that have responded did so for commercial reasons (E3 2012, p. 2).[31] It could be expected that other brands would respond if consumer (and network) demand for direct load control were sufficiently high. Indeed, information provided by a network business indicated that by early 2013, even more air conditioners were configured for direct load control, and major appliance retailers were advertising their benefits over alternative units. Their uptake would be further hastened by:

- the wider global uptake of energy management technologies. It is hard for Australia to act as a first mover in this area as it is a small country with little domestic capability in appliance manufacturing. An option — already in progress — is for Australia to seek the international adoption of its already highly developed standard (box 10.6; E3 2012, p. 2)
- informing consumers about the benefits of this additional functionality.

However, there are grounds for monitoring the extent of uptake of these technologies and, if rates are low, examining why this might be the case before any consideration of mandating of standards. In particular, until the regulatory barriers to critical peak pricing are overcome, mandating a standard is likely to be premature. A Regulatory Impact Statement concerning a mandated standard is currently underway (DRET 2012a, p. 57).

[31] The committee comprises members from all states and territories, and New Zealand. The E3 program overseen by the committee is part of the National Framework for Energy Efficiency (and is supported by national legislation, which replaces various state-based regulations).

Box 10.6 **The Australian standard for demand response capability**

Published in 2007, the AS4755 *Framework for demand response capabilities and supporting technologies for electrical products* applies to the interface between a demand response enabling device (DRED) and a variety of electrical products. An appliance that includes a demand response interface is frequently termed a 'smart appliance'.

A demand response capability could be applied to the manufacturing standards of numerous electrical devices, but is currently being investigated for air conditioners, pool pumps and electric vehicles. Different parts of the standard apply to particular appliances and each is in different stages of development. Standards relating to air conditioning are most advanced. Compliance with the standard would be included in the energy rating labels of appliances.

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 DRED. The DRED can be:

- a self-contained unit that receives remote signals to control load, processes them according to its settings, and sends instructions to the attached appliance
- 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.

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

Sources: Wilkenfeld (2011a, b).

RECOMMENDATION 10.1

The Regulatory Investment Test for Distribution in the National Electricity Rules should be altered so that a preferred investment option cannot have costs that exceed the benefits. The current $5 million threshold value and the use of exemptions should be reviewed if the test imposes unjustifiably high compliance costs on distribution businesses, the Australian Energy Regulator and other parties.

RECOMMENDATION 10.2

The Standing Council on Energy and Resources should finalise a minimum technical standard for advanced metering infrastructure, including smart meters, which should:

- ***ensure that distribution businesses and other parties can purchase off-the-shelf equipment from global manufacturers of smart meters with no, or minimum, modification***
- ***incorporate capacities for:***
  - ***interoperability with add-on technologies that distributors, retailers and third parties wish to offer customers***
  - ***open access to information for distributors, retailers and third parties, subject to privacy provisions***
  - ***direct load control.***

RECOMMENDATION 10.3

The National Electricity Rules should be amended so that distribution businesses would be able to include the rollout of advanced metering infrastructure, including smart meters, as an eligible category in their regulatory revenue proposals to the Australian Energy Regulator. During the regulatory period, distribution businesses should be able to decide on the timing, location and number of smart meters in any rollout. These changes should be accompanied by:

- ***engagement with consumers and retailers about the process, and the implications of smart meters for them***
- ***the development of an incentive program by the Australian Energy Regulator that takes account of the benefits of smart meters:***
  - ***in reducing network expenditures in subsequent regulatory periods***
  - ***accruing to others in the energy supply chain***
- ***time-based network charges to retailers (recommendation 11.1)***
- ***options for direct load control.***

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.
  - This increases consumption of power during peaks, increasing the need for network investment, and pushing up average prices. Current pricing approaches also mean that those who use electricity less at peak times (often low-income consumers) subsidise those who use electricity more at peak times.
- 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 pay-offs from doing so are potentially significant.
- However, there are many complexities and challenges in giving practical effect to such time-based pricing. A coherent, iterative and consultative implementation process that harnesses the knowledge of those at the coalface is 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). The Commission supports the AEMC's proposal that people can opt into cost-reflective tariffs, or choose to remain on a flat tariff (that would then rise over time as non-peaky users selected cost-reflective prices).
- Such changes would not give distribution businesses carte blanche to gouge consumers. Distribution network service providers would each be subject to an overall revenue cap.
- 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 recommends:
  - 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, distribution businesses must build substantial and costly network capacity for infrequent periods of peak demand. However, where customers' electricity tariffs do not vary over time, these costs are spread across all customers, regardless of any particular customer's actual use of the network in these peak periods. In effect, power use during peak demand periods is subsidised, while power use during non-peak periods is 'taxed' to fund those subsidies.

This misalignment of costs and prices has several major undesirable consequences.

- The ratio of peak to non-peak network prices would be much higher were prices cost-reflective. As discussed in chapter 9, there is compelling evidence that peak demand responds to prices. Collectively, these effects imply that fixed tariffs result in a significantly higher level of demand in peak periods. As is the case with any subsidy that stimulates demand, the value of the additional consumption during peak periods to end users is less than the (substantial) cost of meeting it — a major source of economic inefficiency. The corollary is that in non-peak periods, consumers pay above the real costs of supply, and therefore consume inefficiently low amounts of power at these times.
- Since the level of investment in networks and generation is above efficient levels (leading to higher aggregate electricity supply costs), average electricity prices are higher than they otherwise would be.
- Regardless of the degree to which peak users respond to price changes at peak times, there remains a distributional argument for introducing critical peak pricing. For example, suppose that peak demand was completely unresponsive to price changes. In that case, the required network capacity would be the same regardless of whether networks introduced critical peak pricing or not (and so the *economic inefficiency* of non-cost-reflective pricing would be small). However, with critical peak pricing, non-peaky users would no longer be subsidising peaky users. In contrast, under current flat tariffs, non-peaky users of power face excessively high prices, and cross-subsidise peak users. Often this means that low-income consumers cross-subsidise higher income consumers.

Accordingly, the broad case for embodying a cost-reflective, time-based component in prices for use of network services — and especially the distribution component of the network — is strong.[1] This would ensure optimal network capacity at peak times, recognising that many people will want, and be willing to pay for, additional capacity for very hot or cold days. The conceptual argument has long been

1 In chapter 19, the Commission recommends various changes to achieve more efficient charges for transmission network services. However, the broad underlying goal is the same as for time-based pricing for distribution networks considered in this chapter.

recognised (Joskow and Wolfram 2012). The empirical evidence from trials also suggests that once people have experienced time-based charging, most are satisfied with it.[2] More importantly, as shown in chapter 9, the efficiency and equity pay-offs from introducing generally applicable, cost-reflective, time-based pricing — hereafter referred to simply as cost-reflective pricing — would be potentially large.

Cost-reflective pricing is 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. Moreover, the smart meters necessary to implement cost-reflective pricing at the household level are readily available and already in place in much of Victoria. Ausgrid has already rolled out nearly half a million interval meters in New South Wales, and has installed 16 000 smart meters, mainly as part of the Australian Government's Smart Grid Smart City Trial (Ausgrid 2012g).

It is therefore unsurprising that many major players are supportive of removing obstacles to the use of cost-reflective pricing by networks and retailers. These include the Australian Energy Market Commission (AEMC), Major Energy Users and most peak industry bodies representing the supply chain (such as the Energy Networks 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.

Given that the case for a shift to cost-reflective pricing has already been made in chapter 9, this chapter concentrates on how to *practically* achieve that outcome. Implementing widespread cost-reflective pricing will involve many complexities and challenges, not the least of which is ensuring households and other consumers understand its implications and the means by which they could adjust their power use in response to it. The goal should not be to achieve the perfect scheme that accords with some textbook. Rather it should be to develop a workable, and broadly acceptable, approach that generally avoids the costs of catering for critical peak load demand that consumers would be unwilling to pay for were they to be charged genuinely cost-reflective prices.

Any reform in this area needs to take account of existing pricing practices (section 11.2) and any provisions in the National Electricity Rules (section 11.3) that may limit reform. Defining the basis for cost-reflective prices is not trivial, and requires pricing that signals where and when a business needs to expand its network — an issue examined in section 11.4. Implementing cost-reflective pricing requires a carefully sequenced set of changes including:

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2 For example, Sergici and Faruqui (2011, p. 13) and Frontier Economics and Sustainability First (2012, pp. 32-3).

- institutional arrangements that will provide a continued impetus for pricing reform (section 11.5). Reform must be gradual, coordinated and involve consultation with all stakeholders, but it must also have timelines
- a National Electricity Market (NEM)-wide framework (section 11.6)
- a supporting set of regulations and guidelines (sections 11.7 and 11.8)
- the need to address affordability and equity issues, predominantly the requirement that there are well designed, targeted mechanisms in place to assist those vulnerable consumers who would be disadvantaged by the changes (section 11.9)
- the transition to cost-reflective pricing (section 11.10)
- the need to bring all the various stakeholders on board by providing assurance that the reforms would be workable and beneficial, and particularly the critical need to engage and educate consumers (section 11.11).

11.2 How do distribution businesses currently price?

There are multiple ways of recovering the costs of distribution network businesses (box 11.1), and their application varies by customer class. The largest industrial and commercial users often already face cost-reflective prices, and the use of such pricing is extending to other large users.

However, for most households and small and medium enterprises, costs are recovered through a fixed charge and an energy use charge. Time-based charging of any kind is mainly limited to trials. Even where there are time-varying prices for households, they usually take the form of untargeted time-of-use (TOU) tariffs. These apply ‘peak’ prices for long periods of every day, instead of targeting the few hours of critical peak demand.[3] Given this, the ratio of off-peak and peak prices in TOU tariffs tend to be low, and accordingly, their effect on consumer behaviour also appears to be muted (Futura 2011, pp. 13-15, p. 60). Overall, the implication is that distribution businesses recoup a high and excessive proportion of their costs from non-peak energy usage charges (AEMC 2012b, p. 21; box 11.2).

3 Even where the technology supports TOU pricing, its uptake appears relatively low. The ENA noted that only around 30 per cent of customers using interval meters in New South Wales choose a TOU tariff (trans. p. 335) — but this may partly reflect the fact that untargeted TOU tariffs do not create much of an incentive to vary usage by time.

Box 11.1 **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 set out below.

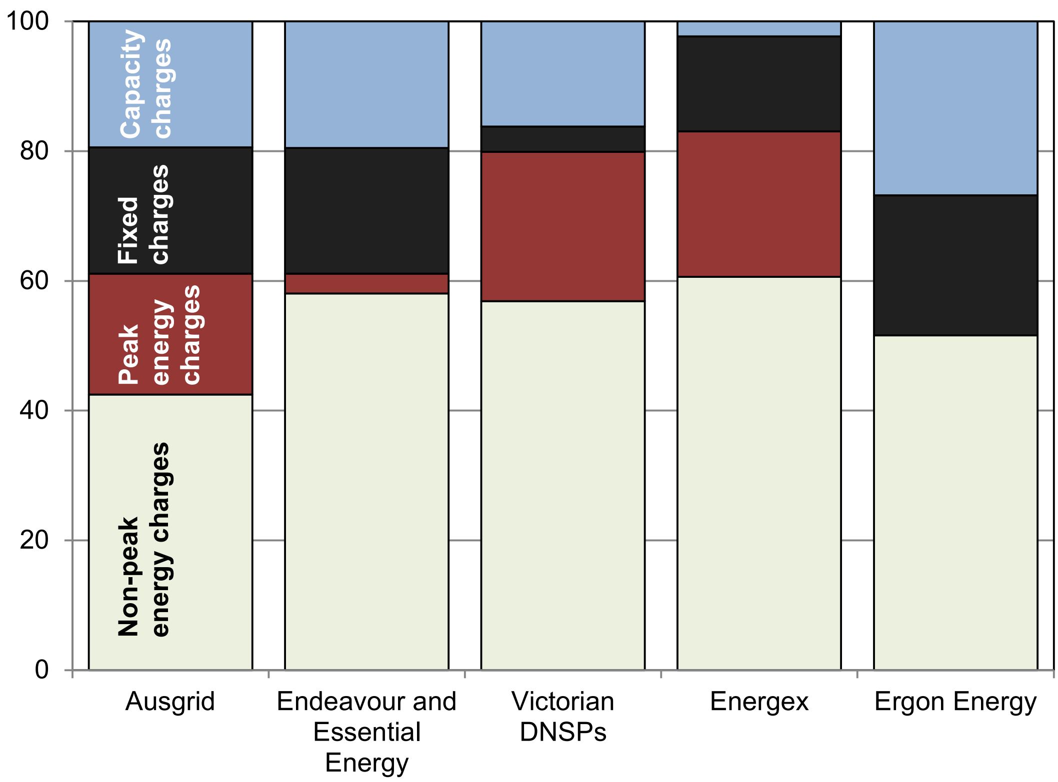
- *Time-based pricing/ time-dependent pricing* — terms often used interchangeably to refer to prices that vary over time. The usual time dimension is hours, but prices may also vary from season to season or from weekday to weekend.
- *Cost-reflective pricing of the network* — requires that prices signal 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 1000–3000 '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 40–80 or so hours a year. Hence, the 'peak' price under a TOU tariff does not, by itself 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 applied very narrowly to signal when demand is very high and supply very tight. A CPP is applied when a distributor declares a critical peak event. Where they have been applied for industrial or commercial users, it has usually been for a two to six hour window on five 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 two hours prior to commencement. Where applied, CPPs have been set to reflect the full cost (see below) of meeting a customer's peak demand. They then have an informed option of how much energy to consume during the peak.
- *Peak capacity charge* — this is specific to a given customer (rather than a customer class) and usually only applies to users with high energy demands. Different networks use different methods for calculating the charge, but in each case, the charge takes account of the fact that for a network, it is the maximum requirement for power, not energy flows per se, that is a major contributor to network investment (Ausgrid 2012d, p. 55). For example, SP AusNet (2013b, p. 50) bases its capacity charge for a low-voltage business user on the nameplate rating of the transformer supplying the customer. In Ausgrid's case, for any given customer, the charge is the maximum (the so-called 'Billable Maximum Capacity') over the past year of the half hourly *power* readings (in kW or kVa) from the relevant peak periods. For example, this is 2 pm to 8 pm on week days in Ausgrid's network (2012d, pp. 52ff). In Ausgrid's case, capacity charges require a meter that can record 30 minute interval power (Type 5 or better meters — chapter 10).
- *Peak charges based on Long-Run Marginal Cost* — the components of an overall tariff that reflect the marginal network cost of supplying peak demand over a period that is sufficiently long to make all costs (including capital) variable.

Box 11.2 **How are peak network costs currently recovered in charges?**

Victorian and New South Wales distribution businesses recover between 40–66 per cent of their total revenues through non-peak usage charges, with smaller proportions recouped from peak period and fixed charges. For households, which rarely face any time-based prices, the reliance on non-peak usage charges is higher again. Capacity charges are mainly applied to large business users (box 11.1).

However, Ausgrid has recently sought to rebalance its tariffs, increasing the proportion of its revenue recovered through fixed charges and peak energy charges (Ausgrid 2012b). 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 standard interval meters has assisted Ausgrid to rebalance their tariffs.

Revenue recovered by tariff component for all customers
Per cent, by Victorian and New South Wales distribution network service providers[a]



[a] Ausgrid, Essential and Endeavour Energy, Ergon 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).

Sources: AER (2012n, pp. 124-7); Ausgrid (2012b, p. 12); Ergon and Energex (pers. comm., 2013).

The limited use of genuine cost-reflective pricing reflects several factors.

- Most importantly, most customers do not have interval or smart meters capable of recording energy use or power requirements by time.
- Retail prices are often regulated, which means that any pricing flexibility at the network level can only be imperfectly replicated at the retail level. That severely mutes any possible demand response, thereby forgoing the network savings that motivate cost-reflective pricing in the first place.
- Governments are likely to be more sensitive to losers than winners from pricing reform. There is also a (generally poorly informed) concern that time-based pricing adversely affects lower-income consumers. There is an associated view that where this is so, tariffs for all consumers should be re-structured to ameliorate this. While it is appropriate for governments to protect vulnerable consumers, this should be achieved through transparent and targeted measures — such as formal community service obligations or obligations written into the National Electricity Law and the Rules (a matter covered in greater detail in section 11.9). Businesses would then set tariffs, subject to the regime regulated by the Australian Energy Regulator (AER). However, state governments continue to set licence conditions and, therefore, have a pervasive influence on businesses' activities. Some privately owned distributors claim to be influenced by unwritten 'guidance' from jurisdictional governments (which is backed by their potential to write conditions into licence agreements or to restrict other aspects of commercial activity, if businesses do not fall into line). The 'moratorium' on time-based network pricing in Victoria (which is to elapse in 2013) is one such example of the latter, with its implementation more akin to a 'gentlemen's agreement' unsupported by any specific written direction.

11.3 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.[4] 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 AER can pursue changes to non-compliant proposals.

However, the pricing rules provide very little real guidance about prices. Among other aspects, the Rules specify that prices for a specific retail class of customers

4 This and other references in this chapter to particular clauses refer to version 54 of the Rules.

must lie *somewhere* between the avoidable and stand-alone costs of supplying them. The former represents the cost savings from not serving a particular tariff class, assuming network businesses continue to provide all other services. The latter represents the much higher cost from serving the customers concerned, with all other customer types not being supplied. The gap between the two is often described as the 'subsidy-free zone', because if prices are lower than the avoidable costs, the relevant customer class is being subsidised by others, while if prices are higher than the stand-alone costs then they are clearly paying too much (subsidising others).

Unsurprisingly, given the economies of scale and scope that characterise distribution, there can be a large divergence between these lower and upper cost bounds.[5] This means that within an overall revenue or price cap, a wide mix of charging structures that potentially have little resemblance to efficient pricing will be compliant with the rules (table 11.1) — a point also emphasised by the AEMC (2012u, p. 184).

In fact, neither price bound is appropriate. Instead, long-run marginal cost (LRMC) pricing (box 11.2) is widely regarded as the most efficient (as explained further in section 11.4). Though not silent on the value of LRMC pricing, the Rules give it more of a passing nod than a real endorsement — businesses 'must take [the concept] into account' in deciding tariffs or charging parameters (clause 6.18.5(a)). 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 significant deficiency in the Rules is that the apparent 'subsidy free zone' between the stand-alone and avoidable costs is more apparent than real. This reflects the broad description of customer classes. Customer classes must share *some* common features, such as voltage levels, the amount of power used and the nature of the end use (domestic, business, commercial or industrial).[6] There remains plenty of scope, given such general classes, for significant variations in the patterns of consumption of their constituent customers, and accordingly, in the costs of supplying them. In particular, the Rules do not constrain large cross subsidies between customers with peaky consumption patterns and those without.

5 This margin is even wider if the ambiguity and problems in defining both bounds are considered. This is highlighted by the examples of calculations of stand-alone costs given by Turvey (2000b, pp. 42-3), who characterises it as lacking all practical interest. ETSA Utilities (2011) revealed many of the difficulties in its calculation.

6 As spelt out in clause 6.18.4. In practice, it excludes geographic location (although the Rules would allow it).

Therefore, as discussed in section 11.7, the Commission considers that a tightening of Clause 6.18.5(b)(1) would help in facilitating time-based pricing for distribution networks (as well as to support some other efficiency enhancing pricing reform).

Table 11.1 **Estimates of annual distribution network costs and charges**

Business	*Tariff class*[a]	*Stand-alone cost*	*Avoidable cost*	*Tariff revenue*
		$m	$m	$m
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	2 129	263	2 047
Ausgrid (2010-11)	Sub-transmission	598	3	5
	HV business	880	5	38
	LV business	1 384	58	672
	LV residential	1 405	178	745

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

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

11.4 Designing time-based prices for distribution networks

LRMC as the underlying basis for time-based distribution network charges

Many see network services as a single product — transporting power — when in fact, they are comprised of many different products, each with different long-run costs. In particular, the long-run costs of supplying power at peak use times are quite different from other times, because a substantial amount of additional investment is required to supply the former. In that sense, peak and off-peak network services can be seen as related, but different products. As for products throughout the economy, efficient pricing aims to achieve a reasonable alignment between prices paid by consumers and the costs of supply.

A wide body of economic literature and other opinion identifies LRMC pricing as the appropriate pricing methodology to achieve this efficiency goal.[7] LRMC is the marginal network cost of supplying peak demand over a period that is sufficiently long to make all costs (including capital) variable. A business must charge at least LRMC to avoid a loss. (In contrast, short-run marginal costs take existing capital as given, and prices based on SRMC will not allow a business to recover sufficient revenue to finance future required investment.)

There are many practical challenges in calculating LRMCs — brought into focus by the AEMC (2012u, pp. 184-5); Marsden Jacob Associates (2004) and Turvey (2000b, p. 2). The appropriate method depends on many factors, including:

- the reasonableness of forecasts of future required capacity and technological change, recognising that LRMC is a forward looking cost measure
- the specification of the appropriate increment, recognising the lumpy nature of the relevant investments[8]
- the appropriate time horizon over which to make the calculations
- the discount rate (the use of which is required because all measures of LRMC must discount future streams of costs and outputs into a single number)
- preferences about price stability. (Some measures of LRMC imply more volatile price paths than others.)

LRMCs must recognise the practical engineering and commercial realities of how network augmentations proceed. As Turvey (2000b, p. 46) notes 'The forecast cannot be made without the collaboration of engineers' — which is why harnessing the expertise of the networks is critical.

Not surprisingly, there are several methods for calculating LRMC — each with its own advantages and disadvantages (covered in detail by Marsden Jacob and Associates, 2004).[9] This is a highly technical area — with the choice determined by data availability and the purpose of the cost measure, among other factors. The

[7] Many participants and others have also made this point (Deloitte 2012, p. 20; AEMC 2012u, pp. 181ff).

[8] 'Lumpy' network investments are large forward-looking investments made at infrequent intervals, usually associated with some significant step upgrading of the capacity or reliability of the network.

[9] These include marginal incremental costs (MIC), average incremental costs (AIC), and long-run incremental costs (LRIC).

complexity is revealed by the diversity of approaches used in utility regulation in Australia and overseas.

However, it is possible to produce some meaningful estimates, and even proxies for LRMC are likely to provide a basis for prices that better signal the true costs of meeting peak demand than do the prices currently charged to most customers. The practical difficulties of estimating LRMC are not much different from other markets where time-based pricing applies.

Once computed, the LRMC could be incorporated in charges in several ways — including volumetric charges, access charges, charges linked to a customer's maximum demand, and targeted charges based on particular demands placed on specified 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 distribution network businesses' pricing proposals to the regulator would involve significant and appropriate use of critical peak prices, and (especially for business customers) peak capacity charges.[10]

LRMC pricing for peak demand by distribution businesses would have several major implications.

- Prices would be higher at peak times because of the greater long-term costs of supplying at peak times.
- Consumers would only use power at critical peak times up to the point where they would be willing to pay for it — an important efficiency criterion.
- The latter in turn offers scope for major savings from deferring costly new investment to meet typically short-lived peaks in demand.
- The overall electricity charges for consumers who tend to use less peak power would decrease, eliminating cross-subsidies, often to the benefit of lower-income consumers.

[10] This is not novel. The pricing arrangements set out in the Rules for transmission services (clause 6A.23.4(e)) indicate that prices for recovering the locational component of providing prescribed Transmission Use of System services *must* be based on demand at times of greatest utilisation of the transmission network and for which network investment is most likely to be contemplated.

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. Ideally, significant differences of this nature should be reflected in an efficient time-based pricing regime. As AEMC (2012e) observed in its Power of Choice Directions Paper:

> DNSPs [Distribution Network Service Providers] 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. (p. 64)
>
> Where the network costs of supplying consumers differ by location, the network tariff should likewise vary by location. (p. 206)

While the Commission has been unable 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. The latter observation is supported by AEMC data showing that peaks are typically in summer in South Australia, Victoria, Queensland and New South Wales, and over winter in Tasmania (chapter 9).

NSW DSNPs (sub. DR85, pp. 6-7) claimed that temperature trends were changing by jurisdiction, which, if they continued, would also affect the future geographical pattern of peak demands. For instance, according to their submission, Queensland, and to a lesser extent New South Wales, has shown a trend towards more warm days, while this pattern has not occurred in Victoria.

Again, the precise way in which time-based prices should encompass significant geographical differences in costs related to peak demand is a matter for distribution businesses, the regulator and their customers, but should not be frustrated by the Rules.[11] 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

[11] In its final Power of Choice report, the AEMC (2012u, p. 282) reached the same conclusion.

- the location of end users relative to generation sources and, hence, their call on distribution poles and wires
- 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 (recommendation 11.8). It is not clear that support should go beyond vulnerable groups.

- Support has to be funded from either taxpayers or other consumers, many of whom may be poorer than the parties they end up subsidising.
- For many other goods (such as food and petrol), governments do not remove regional variations arising from the higher costs of serving some customers.
- Moreover, where governments do apply postage stamp pricing, the quality of service is usually not constant across regions. For example, in electricity, interruptions are more frequent in non-metropolitan areas. Once quality is taken into account, the effective price of services in many regional areas is higher than the notional price would suggest — suggesting that some degree of real price variations is already acceptable.
- Requirements for cross-subsidies from low- to high-cost regions would undermine the motivation for network businesses and communities to seek alternative lower-cost solutions for transporting power (for example, distributed power).

However, in the event that governments wish to smooth regional cost-based price differences, they should do so to the least extent possible, with any such support transparent and delivered efficiently (see below).

How good is the current information on LRMCs?

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

> It is of course immensely difficult to accurately measure the long-run marginal costs of consumption. These are in a state of constant flux, and are affected by both 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 investments costs and perfect information of future technological advances. (SP AusNet 2012, p. 46)

Moreover, network investments are not just related to peak load growth (or options to cost-effectively manage demand). The need to replace ageing assets and 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 circumstances,[12] 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, distribution businesses have tended to use compromised forms of LRMCs for setting charges, which usually straddle a mix of marginal and average cost concepts. Nevertheless, there are many published estimates of LRMCs for distribution networks that can be used as a starting point for pricing supply at critical peaks.[13] Better information would help develop improved measures of relevant LRMCs. The increased use of smart sensors to collect load data at a fine detail across networks may assist, extending the data already available at the zone substation level (Leung 2012).

Some related demand forecasting issues

Forecasts of peak 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 by distribution businesses would increase the complexity of the AER's task in this area, as would the way in which retailers choose to pass through such prices (Ergon Energy, sub. DR63, p. 7). Specifically, there would 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 noted earlier, the Commission recommends a change in the Rules to achieve this (recommendation 11.5).

This added dimension to the revenue determination process could, if undertaken well, provide a potentially powerful spur for distribution businesses to implement efficient time-based pricing. That is, a distribution business that did not implement time-based pricing to the degree provided for in the determination could expect to

[12] And depending on the precise methodology adopted to calculate LRMC.

[13] Among these are Colebourne (2010), ETSA (2012a), Futura (2009), Oakley Greenwood (2010b) and the many estimates cited by Deloitte (2012). The Commission used these to estimate some of the benefits of various demand management options (chapter 9). There are few publicly available estimates for transmission networks.

experience a net revenue shortfall over the regulatory period. Fundamentally, this is because it would be obliged to build capacity — at high cost — for the increased peak demand arising from non-cost-reflective prices. Yet its regulated revenue allowance would not be enough to recover these costs because the AER would have based the allowance on lower demand forecasts and lower investment requirements.

Inevitably, distribution businesses and the AER will make errors in calculating the LRMC and in estimating the demand response to peak pricing. The issue is how to test whether pricing is moving in the right direction and to limit the scope of those errors and their consequences. In the medium term, a test of improvement would be evidence of a substantial widening of the gaps between off-peak and critical peak prices. If this did not eventuate, the incentive regime (and the Rules and guidelines that underpin them) would have to be re-visited. A prerequisite for any such improvement would be elimination of the other important obstacles to peak pricing — retail regulation and the absence of smart meters.

Given the greater role for LRMCs in determining peak prices and generating demand forecasts, it would be important for the AER to have a strong and growing capacity to assess the reasonableness of LRMC estimates and their implications for demand forecasts. (This provides another reason for additional resourcing of the regulator — chapter 21.) The iterative process of developing better estimates of the LRMC is a form of benchmarking in its own right — albeit one that targets allocative efficiency by establishing a LRMC price benchmark, rather than technical efficiency, which is the more usual focus of benchmarking exercises.

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). In this respect, ongoing trials should assist in price setting and in the more precise estimation of demand elasticities. After the Victorian Government lifts the moratorium on time-based pricing, experiences in that state should also provide lessons to distribution network businesses in other jurisdictions. For example, Jemena, a Victorian distribution business, is transitioning to cost-reflective network tariffs in 2013 (sub. DR77, pp. 15-16).

Defining ‘peak’ demand

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 the concept of ‘peak’ periods much too broadly and frequently to materially moderate critical peak network demand and the investment burden that comes with it.

However, there is no clear consensus on how peak demand, 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 difficulty of defining peak demand. Also, the demand response of some customers to time-based pricing will moderate peaks, as these customers will 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 load profile.

Given these complexities, the Commission has not sought to specify how peak demand should be defined within a time-based pricing regime. Rather, distributors should determine this, in consultation with the other relevant stakeholders as part of the implementation process. However, the Commission reiterates that peak period charges that drive augmentation investment should be much more targeted to actual demand peaks than at present. Some other key considerations for any definitions include:

- the capacity to translate definitions into 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 there should be a tradeoff between, on the one hand, the benefits of continually finessing tariffs and, on the other, the transactions costs for retailers and consumers associated with constant change and complexity. This suggests some gradualism in adapting tariffs over time. It also indicates the importance of engagement between network businesses, retailers, customer representatives and the AER on the means of iterating to a robust time-based charging regime.

11.5 A supervising role for SCER is a first step in implementing time-based pricing

Given the complexities of the task, the many other required changes in the system, and the likely aversion of some stakeholders to moving to time-based pricing, there is a risk that reforms will be either insufficiently coordinated or could stall. It is more likely that reform will occur if it is coordinated by a single body, which would establish realistic reform milestones and timelines, oversight progress against those timelines and, if required, bring stakeholders together to resolve specific roadblocks or unduly slow progress.

In principle, the Standing Council on Energy and Resources (SCER) would be the most appropriate body. It has responsibility for pursuing priority issues of national significance in the energy and resources sectors. Among its 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 network pricing.

However, there is a complementary need for SCER to ensure that reform occurs in a timely way to maximise the benefits to consumers of efficient pricing (chapter 21).

RECOMMENDATION 11.1

The Standing Council on Energy and Resources should oversee the progressive implementation of cost-reflective, time-based pricing for 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 proposed process (recommendations 11.2 to 11.9)***
  - ***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.***

11.6 A NEM-wide licensing regime for network providers

One step that could be taken reasonably quickly to facilitate the implementation of time-based pricing for distribution networks would be to establish a single set of licence requirements for all network providers operating in the NEM. These should replace the current state and territory provisions, with the new requirements incorporated in the Rules. Such a licensing regime would reduce the risk that the pursuit of objectives other than the National Electricity Objective by state and territory governments could frustrate the introduction of cost-reflective, time-based network pricing. A shift in responsibility for enforcing compliance with licence conditions to the AER would be no less important than a move to common requirements — particularly in jurisdictions where governments also own the network providers.

In making these observations, 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. However, 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), relative to the costs involved in upgrading networks, are seemingly ignored (chapter 14). And of more direct relevance to time-based pricing are instances of jurisdictional governments intervening implicitly or explicitly to modify charging regimes for equity reasons, such as:

- the Victorian Government's moratorium on time-based charging
- 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
- the Queensland Government's direction in 2011 to its state-owned distribution businesses (Energex and Ergon Energy) not to recover from consumers $100 million of additional revenue that was approved following a merits review by the Australian Competition Tribunal. The Government, as the owner of the two companies, indicated that it would accept a lower rate of return on its equity.

Such instances are in conflict with the principle endorsed by all Australian governments that support for low-income or disadvantaged consumers should be provided through targeted and transparent instruments.

A single licensing regime would also have wider benefits — including for the transmission component of the NEM and by assisting the introduction of:

- a NEM-wide reliability framework (chapters 15 and 16)
- a common and efficient approach across jurisdictions to the provision of assistance to vulnerable consumers (see below).

Since the new licence requirements would replace existing jurisdictional licensing arrangements, they would not result in duplication and higher administrative burdens, and could encompass any relevant properly justified factors that vary between jurisdictions (concerns expressed by the ENA, sub. DR71, attachment 1,

p. 9, trans. p. 330). Jemena (sub. DR77, p. 9) expressed the view that licence conditions should be somewhat like a driver's licence, being:

> … a minimal document simply certifying that the holder is a fit and proper person to engage in the licensed activity. All the conditions that attach to a licence should be contained in applicable law and other enforceable instruments external to the licence. The licence itself should not be a vehicle for promulgating policy.

However, current licences *already* act as vehicles for policy — albeit without much transparency or accountability. In that context, the Commission's expectation is that a robust and transparent process (similar to that of a Regulatory Impact Statement) would inform the development process to minimise the possibility of gravitation to the most stringent (and costly) jurisdictional provisions in each area. This process would also help ensure that the subsequent licence conditions delivered net benefits to the community.

The Commission considers that the development of aspects of these new requirements might sensibly be tasked to the AEMC, which could undertake a framework review to assist the process of developing national conditions. The views of state and territory governments would be central to that review. 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) could demonstrate that the benefits exceed the costs.

The AER would be responsible for enforcement of most new licence conditions and, where necessary, would seek advice on technical issues from the Australian Energy Market Operator (AEMO) or state-level regulators. However, for national licence conditions relating to safety, it would be appropriate for independent national or jurisdictional safety regulators (but not state or territory governments) to ensure compliance, rather than the AER. Nevertheless, as an economic regulator, the AER would still oversee incentive arrangements in technical areas, such as the Service Target Performance Incentive Scheme (and if nationally adopted, the F-Factor scheme).

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

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. These proposals address widespread concerns among participants about protection for vulnerable or disadvantaged consumers (Paul

Brand, sub. DR53; National Seniors Association, sub. DR62; Origin, sub. DR64; MEA, sub. DR74; NAGA, sub. DR88). Suffice to say at this point, 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 provide 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.

RECOMMENDATION 11.2

The Standing Council on Energy and Resources should initiate a process to establish uniform licence conditions for all transmission and distribution network businesses in the National Electricity Market.

- ***The uniform licence conditions should have regard to the Commission's proposed changes to the reliability framework (recommendations 15.1 and 16.1) and should not 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.***
- ***Standardised provisions governing technical standards and safety should ultimately be encompassed in the national licence conditions, but with a transition to recognise the practical implementation difficulties of any rapid changes in this area.***

The Council should task the Australian Energy Market Commission to undertake a framework review to assist the transition to uniform licence conditions.

- ***The supporting framework review should clearly spell out the justification for any jurisdiction-specific conditions included in the new licensing regime.***

RECOMMENDATION 11.3

Before incorporation into national licence conditions, preparatory work should be undertaken to develop a common approach to the identification of customers in need of special support to meet their electricity bills (recommendation 11.8).

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.

RECOMMENDATION 11.4

The Australian Energy Regulator should be responsible for ensuring compliance with most new licence conditions, with the exception that a relevant independent national, state or territory regulator should have responsibility for compliance with national safety licence conditions.

- ***The Australian Energy Regulator would still oversee any economic incentive schemes relating to safety and would need to ensure that revenue determinations took into account the agreed national safety standards.***

The Australian Energy Regulator should be given authority under the National Electricity Rules and the National Electricity Law to:

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

11.7 Tightening and augmenting aspects of the Rules

As discussed earlier, the Rules are vague about the use of LRMC for price setting. The Rules permit such pricing, but do not require it. The key clause in this regard is 6.18.5(b)(1), which requires only that LRMC be 'taken into account' when determining tariffs. The clause has had little impact — as shown by actual network pricing structures (box 11.2). Accordingly, an important precursor to pricing reform is greater discipline in the Rules about the application of LRMC principles.

ActewAGL (sub. DR59, p. 5) argued against any change, claiming the framework of the Rules allow it the flexibility to develop appropriate TOU pricing. Similarly, CitiPower et al. claimed that the current Rules do not present an obstacle to network tariff reform and that Rule changes — to strengthen the requirement for distribution businesses to propose tariffs that reflect LRMC — are not necessary (sub. DR90, p. 19).

However, commenting on the current Rules, SCER has 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 2011a, p. 12)

The AEMC's assessment is equally critical:

> … while LRMC is a fundamental concept for efficient pricing, it is reflected as a relatively weak obligation in the rules. (AEMC 2012u, p. 185)

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 depend on progress in implementing the other preconditions for time-based pricing. This timing might reasonably be the subject of discussions between stakeholders and SCER as part of the latter's proposed oversight responsibility (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, while recognising the practical computational challenges.

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. Currently, 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 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 an amendment to remedy these shortcomings. The AEMC has proposed a similar improvement to the distribution pricing principles via a rule change (AEMC 2012u, pp. 185-6). Such changes would not give distribution businesses carte blanche to gouge consumers. Under the Commission's proposals, all distribution network businesses would be subject to an overall revenue cap (chapter 12).

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 effects of time-based pricing in constraining demand. Otherwise, regulatory revenue caps will be higher than necessary, providing windfall gains to distribution businesses. To discharge this responsibility successfully, the AER will need to develop its demand forecasting capacities.[14]

RECOMMENDATION 11.5

When the process of implementing cost-reflective, time-based prices for distribution network services is sufficiently advanced, the National Electricity Rules should be amended to:

- ***ensure that any time-based tariff is determined by (rather than 'take into account') a reasonable estimate of the long-run marginal cost for the service concerned***
- ***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)***
- ***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***
  - ***with any deviation from this principle arising from any state or territory government decisions about community service obligations transparently funded by the relevant jurisdiction.***

RECOMMENDATION 11.6

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

- ***can only approve a distribution business's peak demand forecasts if they include reasonable estimates of the likely demand response to critical peak 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.

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14 The Power of Choice review '… considers that there is scope to better enable AEMO to perform its responsibilities with respect to demand forecasting, and to improve its ability to forecast price responsive DSP [demand side participation] in the NEM' (AEMC 2012u, p. 142). The Commission would expect AER and AEMO to cooperate in pursuit of improved demand forecasting capabilities under a cost-reflective, time-based pricing regime.

11.8 Guidelines to support methodological development and data collection

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 LRMC of meeting peak demand. Such guidelines should specify factors to be included in the estimation of LRMC and an approved methodology or methodologies for that estimation. The guidelines should be developed in consultation with network businesses and should not be overly prescriptive. The AER should remain open to the use of different approaches, 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,[15] 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, and will ensure that those using power at peak times pay a genuinely cost-reflective price. This would then see some customers reducing their demand at these times and, accordingly, lower 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.

RECOMMENDATION 11.7

The National Electricity Rules should be amended to:

- ***require the Australian Energy Regulator to publish guidelines on the appropriate methods 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 guidelines about efficient, time-based tariff structures, including definitions of 'peak' pricing events.***

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[15] The Power of Choice review also proposed that National Electricity Rules distribution pricing principles be amended to provide better guidance for setting efficient, flexible network price structures and the AER develop and publish a guideline for network tariff arrangements (AEMC 2012u, p. 181).

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 notes that the AEMC has made a final rule determination that will require 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 (AEMC 2012c, p. i). This should help to overcome some of the current gaps in the data relevant to estimating locational differences in the cost of meeting peak demand. Such information would assist networks in incorporating a geographical dimension in future time-based prices.

11.9 Addressing affordability and equity issues

Perceptions about the effects of time-based charging on equity have been an obstacle to the use of time-based pricing in Australia and overseas.

The distributional effects of time-based pricing

Cost-reflective, time-based pricing may see distribution businesses 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
- 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 should 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 those times. In its recent submission to the Senate Select Committee Inquiry into Electricity Prices, the South Australian Council of Social Service (2012, p. 16) noted that:

- low-income households have less peaky demand because their houses are usually relatively small, air conditioning penetration is lower, and where air conditioners 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, inevitably *some* low-income households, or otherwise vulnerable consumers, would be 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 — including the cost of distribution network charges they incur. However, not all forms of intervention are equally efficient. 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 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, utility services are already subject to targeted mechanisms for assisting vulnerable consumers (box 11.3). 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 might 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 air conditioners compatible with direct load control, or for improving the thermal efficiency of their dwellings (chapter 10). These could be funded from general government revenue or by a small publicly-divulged 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 and transfer system (see below).

Some other options that have been suggested would be inappropriate. For example, common prices across regions with very different costs of service would poorly target the people who justifiably need assistance. Similarly, a universal exemption from time-based pricing for low-income groups would be a blunt instrument. For example, it would include people who could shift their demand readily were they to face higher prices. The greater the carve outs from cost-reflective pricing, the lower are the network savings and the higher are average network charges for non-peak use and the associated hidden cross-subsidies.

Box 11.3 **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 cardholders), 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 five million cardholders (including 3.6 million Pensioner Concession Cardholders).

Energy concessions and rebates are generally worth \$200–\$400 a year to the recipient, although in Victoria the amount of assistance is determined as a percentage of the electricity bill (AEMC 2012w, 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 with delivery through cross-subsidised usage charges, these forms of assistance can better target those in genuine need and involve smaller costs to efficiency.

Current arrangements for delivering support must be improved

Given 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 incorporated in the new NEM-wide licence conditions for network providers (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 concessions 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
- 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 in affording utility services appears a strong one, the best way forward is less clear — with the choice in practice being between imperfect alternatives.

Accordingly (and consistent with the Commission's 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's 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 (and may also require an obligation, under the National Energy Consumer Framework, for retailers to pass these on as tariff reductions).

RECOMMENDATION 11.8

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 fixed component of network charges.***

The Standing Council on Energy and Resources should develop common criteria for identifying who should receive such assistance and how it should best be delivered. 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 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 (recommendation 11.2).

11.10 The nature of the transition to time-based pricing

The widespread use of targeted time-based pricing for distribution network services is a big change from past practice. 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. In addition, some important complementary initiatives are required. Accordingly, a carefully planned transition is essential, which involves appropriate engagement between the various stakeholders (section 11.11), 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 SCER (recommendation 11.1).

A relatively easy first step would be to extend cost-reflective, time-based, pricing of the network to all major industrial and commercial customers (box 11.4). Large industrial customers in Australia have had half-hourly interval metering for many years. Many are already routinely being sold electricity based on tariffs and contracts with pricing that varies by time of use (Etrog Consulting 2012. p. 7). Accordingly, time-based pricing in this commercial area is well tested. The Major Energy Users expressed concern that broadening the application of cost-reflective prices to all large users has the potential to create significant and unnecessary price pressures on them (sub. DR66, p. 16). However, this argument is not convincing. Such users would be charged prices that reflected the costs of the services they receive at given times (bringing network pricing into line with the treatment of some other input costs, such as wages). If there are large consequent price pressures (in aggregate) for some users in this group, it presumably reflects the net current (inefficient) subsidies to them. Moreover, price reform must commence with some parties.

However, there would be a longer transition to fully-fledged time-based pricing for smaller businesses and households. This reflects the need for effective engagement by distributors and retailers with customers and a range of complementary reforms, including the:

- removal of retail price regulation (recommendations 12.2 and 12.3). Under arrangements in some jurisdictions, there is currently little scope for cost-reflective network charges to be passed onto customers — obviating the purpose of efficient network pricing. Moreover, retailers with a greater share of peakier customers would be forced to absorb the extra costs of such users. The Energy Retailers Association of Australia stressed that in any transition to TOU prices it is essential that retailers not be obliged to absorb costs arising from network tariffs that they cannot pass through to consumers (sub. DR76, p. 5)

- gradual rollout of smart meters targeted at areas where network capacity limitations are greatest (chapter 10). This suggests that cost-reflective pricing for households and businesses would initially only occur in some regions. It should not be problematic to have households in one area on flat tariffs and others in another area on time-based charges, as this already occurs in trials of time-based charges. Nevertheless, ultimately all customers would face time-based charges.

Box 11.4 **Time-based network pricing regimes for industrial and commercial customers**

Current time-based pricing regimes for larger industrial and commercial customers provide one indication of the sorts of tariff structures that might emerge where time-based pricing is extended to other customers, including households.

SP AusNet's critical peak network tariffs for businesses apply from 2 pm to 6 pm on five nominated days across the December to March period. Its charges are uniform across the network. SP AusNet uses weather forecasts to signal the likelihood of a nominated critical peak day up to a week in advance, and will confirm by 2.00 pm (AESDT) of the preceding day that critical peak event tariffs will apply.

As an example, its Critical Peak Demand Multirate tariff for one set of large customers comprises an off-peak charge of 3.252 cents per kWh and a standard peak charge of 5.934 cents per kWh (SP AusNet 2013b). However, during the nominated critical peak events, customers are charged a critical peak price of $58.694 per kVA per annum, where the kVA amount is calculated as the average of the maximum kVA recorded on the five nominated days. For the sake of illustration, were the relevant average to be 200 kVA over the five days, then the customer would be charged around $12 000 for their load demand on the system during the relevant 20 hours. For the sake of simplicity, supposing that the business recorded 200 kVA of load demand *throughout* the entire 20 hour period and that the power factor was unity (that is, the need for correction could be ignored), then the implicit cost per kWh during the 20 critical peak hours would be around $2.95, or nearly 100 times the off-peak price. (The differential would be higher than this if the above assumptions were relaxed.)

These schedules highlight that genuine time-based network pricing can involve some steep, but short-lived price spikes (balanced by offsetting lower prices during other periods), but it is possible to inform customers about when these will occur so they can respond accordingly. However, caution is required in extrapolating likely time-based tariff structures for households from arrangements for larger industrial and commercial customers. An important consideration is the different demand traits of household customers — particularly their peak use patterns. The important point is that it would be distribution businesses in consultation with the regulator, retailers and customers that would be best placed to determine what pricing structures would be most appropriate.

Retailers and distributors must also devise arrangements 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', as discussed in chapter 10).

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 that targets the 40 to 80 hours of critical peak demand a year. While the Commission has not sought to prescribe particular price paths, 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 New South Wales 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 EnergyAustralia customers on TOU tariffs found that 71 per cent believed it was a fairer pricing system (this reflects that untargeted TOU tariffs still 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.

However, these sorts of pricing regimes are unlikely to be effective in ensuring that future investment in the network to meet critical peaks is at a level that is supported by consumers' willingness to pay. Accordingly, they would need to be supplemented by genuinely cost-reflective prices after an interim period. (In a cost–benefit analysis of options to reduce peak demand costs, Deloitte (2012, p. 60) found that untargeted 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 underutilised. Indeed, the Commission's modelling suggests that if the transition to more cost-reflective forms of pricing is too slow, the case for rolling out smart meters in the medium term becomes commensurately more problematic. Nevertheless, TOU pricing may still be a useful long-run complement to critical peak pricing, if for no other reason that it may habituate people to electricity consumption patterns that lower peak use overall. For example, it may promote the use of time switches and direct load control. This may make it easier for people to adjust their behaviour, if they wish to do so, when critical peak pricing is introduced.

A further fundamental issue is the degree to which consumers could choose not to face cost-reflective prices.

In Victoria, where the rollout of advanced metering infrastructure is well advanced, the Department of Primary Industries noted that the transition to flexible network tariffs will be on a voluntary basis for residential customers. This will include a 'safe try' period until March 2015, during which households will be able to switch back to their previous tariff without penalty if they are uncomfortable with the change (sub. DR94, p. 9).

Any capacity to revert to the *original non-time-based* retail tariff would significantly reduce the sort of response that such critical peak prices are intended to induce. Under a voluntary 'safe try' model, many of the peakiest users (the recipients of cross-subsidies and the source of costly network usage) would likely opt to retain the hidden subsidies they receive, largely eliminating the scope for cost savings for those electing to shift to time-based charges. This situation is shown in the left hand chart in figure 11.1. The motivation for moving to time-based charging would therefore be relatively weak.

An alternative approach would be to give consumers several options. They could:

- stay with their current retail tariff structure, which would typically consist of a fixed charge and a usage price not related to the time of energy use. It is important to emphasise that it would be the non-time-based price *structure*, not the price *level* that would be preserved. Even though customers who so elected would not face a retail price that openly reflected the time variant network component, the distribution network business's charges to retailers would still be time-based and would take into account critical peaks. Accordingly, retailers would have to raise the usage charges to householders on non-time-based tariffs to cover the higher costs that they would face during critical peak events
- shift to a time-based tariff determined by retailers (chapter 12), which would contain several pricing choices. For example, it might include TOU charges for winter and summer (with relatively shallow price differentials) accompanied by steep critical peak prices for the few hours a year where the network was under stress.

The AEMC refers to this approach as an 'opt in' model in that people would actively choose the type of retail tariff structure, depending on their consumption patterns, preferences and retailers' offers (AEMC 2012u, pp. 172-3).[16]

[16] The AEMC (2012, p. 173) only proposed this opt-in model for low energy using consumers and businesses (so-called 'band 3' customers). It proposed that large residential and small business consumers above a defined annual consumption threshold (band 1 customers) be required to

While it might appear superficially similar to the Victorian Government's approach up to 2015, the AEMC's proposal would not sustain large cross-subsidies. The term 'opt-in' only relates to the *form* of the retail tariff, not to a capacity to avoid cost-reflective network charges. Over time, the AEMC's proposal would erode the prospects for cross-subsidies. The dynamic would be as follows:

- the distribution network business would charge cost-reflective network charges (with critical peaks) to retailers, in accordance with the pricing principles identified earlier
- retailers would offer a variety of tariff structures, including (a) a standard fixed charge with an energy use charge but no critical peak prices and (b) more complex pricing structures that might include TOU and critical peak prices
- non-peaky users (and those peaky users who would be willing to change their consumption patterns) would logically prefer (b) and so over time would be likely to opt-in to time-based charges. As cross-subsidies were eroded, they would pay less than before. Moreover, likely falling peak demands would produce network savings, further reducing prices
- peaky users on tariff structure (a) would lose some of their cross subsidies, and so their non-time-based network usage charge would rise. This would likely encourage more customers in this tariff category to shift to (b), prompting further increases in usage charges for (a). This iterative process would continue until there was some equilibrium (shown as the right hand chart in figure 11.1). For example, some people might prefer the certainty and simplicity of flat tariffs, even if they were relatively high.

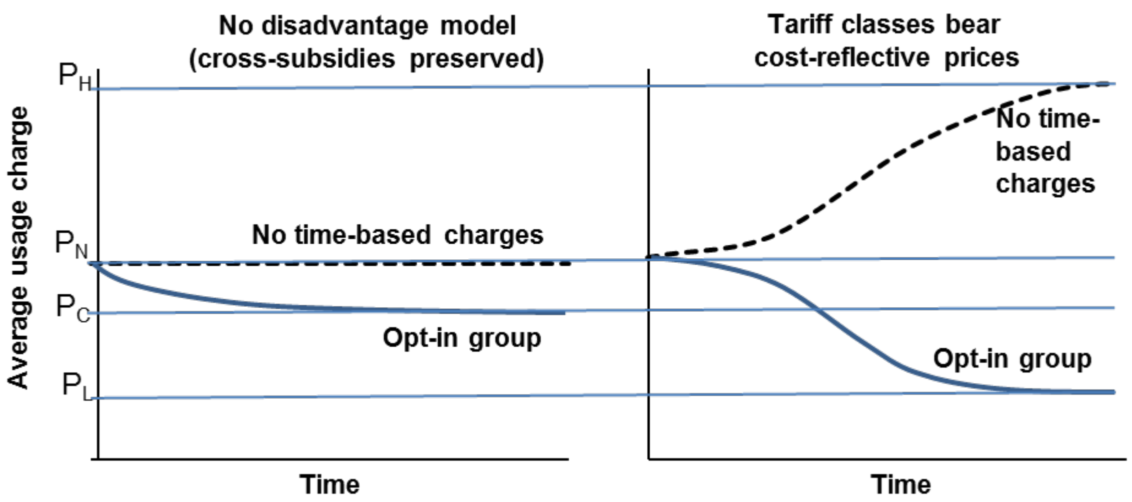
This is a stylised description of the dynamic process that could be expected. For example, in reality, there would be more than one time-based retail tariff structure, as is the case in those trials where distribution businesses have implemented time-based charging. This pricing approach would provide a natural progression to time-based retail tariffs, giving time for retailers and consumers to learn, adapt and plan. However, if the progression were too slow, then it would lower the value of rollouts of smart meters. Without smart meters, there would be no prospect for time-based tariffs — a chicken and egg problem. As discussed further in chapter 12, a more prescriptive approach might be required if retail tariffs did not adequately reflect time-based network prices.

Ultimately, the Commission's expectation, based on time-based pricing regimes for industrial and commercial users (box 11.4), is that household network prices would

have an efficient and flexible network tariff as part of their retail price offer. Finally, it proposed an opt-out model for customers with an annual consumption level below the band 1 threshold but above the band 3 threshold.

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 (such as higher-use periods of the day in winter and summer), but, if so, the peak price would be considerably less than that at critical peaks.

Figure 11.1 **If people can escape the cost implications of cost-reflective prices, it undermines the goal of pricing reform**[a]



a In the left hand chart, the gap between P_N and P_C is for illustrative purposes. The actual gap would be negligible. This is because the scope for network savings relies on demand response at peak times by those consumers not staying with their existing tariffs (the 'movers'). Those savings are likely to be small because movers would be generally less peaky. Moreover, any reduction in off-peak prices for movers will cut overall revenue for the distribution business. This reflects the fact that the typical household demand elasticities for electricity are modest, and that the inflexible prices for the non-movers would not give the network business any opportunity to recover revenue from higher peak charges for this group. Therefore, the network business must balance the loss of revenue from movers against slightly reduced costs — achieving a balance that would not reduce their return on assets. The equilibrium outcome would be a slight differential in average usage charges.

11.11 The importance of effective engagement and customer education

Participants generally agreed that whatever the particular transition path adopted, it is critical that there is appropriate consultation and information exchange between the various stakeholders. As noted by Sergici and Faruqui (2011, p. 19), '… changing a century-old ratemaking practice will require significant customer education and management of expectations'. They also observe that ex ante, many consumers say that they do not want pricing reform, but that after they have experienced such pricing, the vast majority report high satisfaction and want it to continue (p. 13).

One of the tasks of SCER in its role of overseeing the implementation process (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 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, 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. In this regard, the Commission is in accord with the Sustainable Regional Australia (sub. DR72, p. 2), which argued for absolute clarity in assigning responsibility for education of consumers ahead of pricing reform.

Imposing a formal requirement on distribution network businesses 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 11.5).

Similarly, a formal requirement for distribution businesses and retailers to engage with consumers is important 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 benefits 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 11.5 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 network pricing, the complexity of the price formulation process would increase and with it, the administrative costs of reflecting those prices in retail tariffs. (The operation of a centralised smart meter data management system could help to lessen, though not eliminate, this additional administrative burden for retailers.)

Adequately advanced notice of network pricing changes to retailers is important. There is a requirement that distribution network businesses update a 'statement of expected price trends' for each regulatory year (cl. 6.18.9(3) of the Rules). However, prior to an *actual* change in network tariffs, retailers only need to be given 20 business days' notice. In the absence of earlier engagement, such short notice would make a smooth transition to time-based pricing difficult for retailers and their customers. Indeed, the sort of engagement catered for by this rule is seemingly reflective of minor adjustments to pricing regimes than the sort required for major pricing reforms.

A critical issue is whether retail price deregulation and the capacity for cost-reflective prices would result in exposure by consumers to the enormous fluctuations in wholesale energy prices that can sometimes occur (up to $12 900 per MWh or $12.90 per kW). Of course, such high pricing events do not occur often, and they usually do so for only short periods. Regardless, even if permitted to adopt cost-reflective prices for wholesale energy variations, it is unlikely that retailers would change their current practice of hedging, or contracting with generators (thus smoothing of price volatility in the wholesale energy market) for residential customers. This is because such events are not predictable — but can arise from generator failure, strategic behaviour by generators and transmission failures at any time. Consequently, it would be hard to pre-notify consumers of such pricing events. Nor is it clear that where the pricing events result from such unpredictable events (compared with the predictably high costs associated with network capacity built for the hottest days) that it would be efficient to pass on these volatile unhedged wholesale prices to consumers. Consumers value insurance for such unpredictable events. A retailer that failed to provide such a service would be unlikely to retain customers. Large energy users fall into a different category — and will sometimes agree (with the possible involvement of an intermediary) to voluntary load shedding in return for a fee during high price events, thus lowering their overall costs. Such firms or their intermediaries have the facility to continuously monitor five-minute interval wholesale electricity prices and have the ability to take very rapid action to curtail consumption. Households are unlikely (even with the aid of an intermediary) to ever be able to respond in this sort of manner.

RECOMMENDATION 11.9

The Australian Energy Regulator should require:

- ***distribution 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 tariffs. Such engagement should occur sufficiently early to ensure that customers have been:***
  - ***given sufficient information and time to respond appropriately to time-based pricing (including of the various means to manage their peak demand)***
  - ***informed about the implications for their electricity bills***
  - ***given clear guidance about the way in which advance warning of critical peak pricing events will be communicated***
  - ***provided with 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 cost-reflective network charges calls for complementary reforms to the revenue control mechanisms applying to network businesses and to retail price regulation.
- The two main revenue control mechanisms used in Australia — weighted average price caps and revenue caps — impose different sets of incentives on network businesses. These not only have implications for cost-reflective pricing and demand management, but also for investment decisions more generally. While weighted average price caps are, in theory, likely to lead to more efficient pricing outcomes, they also allow network businesses to recover more revenue, on average, than a revenue cap.
  - While each has inherent deficiencies, on balance, the Commission now prefers revenue caps.
- The inconsistency of retail price regulation with the long-term interests of consumers has been acknowledged by all governments in the National Electricity Market — evident by the Council of Australian Government's (COAG's) agreement in 2006 to a process for its removal in electricity and natural gas.
  - However, progress under the COAG process has been very slow with only Victoria and South Australia having deregulated retail prices for electricity.
- The success of, and returns from, the phased and coordinated suite of reforms proposed in chapters 10 and 11 rests on pricing flexibility, competition and innovation in the retail sector, which can only take place through retail price deregulation.
  - The COAG process should be expedited to enable retail price regulation to be removed by no later than 2015. This will require the acceleration of the Australian Energy Market Commission's current timetable of retail competition reviews, particularly for Tasmania and the ACT.
- To support favourable outcomes for consumers choosing between retail offers, the removal of retail price regulation should be accompanied by access to an independent national online information tool to help consumers make good choices.
  - This could build on the Australian Energy Regulator's existing 'energy made easy' online comparison tool.

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

This chapter focuses on three complementary areas for reform insofar as they are relevant to promoting the benefits of cost-reflective pricing and other forms of efficient demand management:

- control mechanisms applying to network businesses (section 12.1)
- the incentives of network businesses to engage in demand management (section 12.2)
- retail price regulation and the incentives of retailers to pass through cost-reflective network charges to consumers (section 12.3).

The chapter concludes with a brief discussion of the Australian Energy Market Commission's (AEMC's) proposal from its Power of Choice review for a demand response mechanism (section 12.4).

12.1 Choice of revenue control mechanism — revenue caps versus weighted average price caps

As part of the revenue determination process, the Australian Energy Regulator (AER) calculates the maximum allowable revenue for each network service provider for the following regulatory period. The process by which network businesses can convert the maximum allowable revenue into network prices is known as the 'revenue control mechanism'. The main control mechanisms currently used in Australia are revenue caps and weighted average price caps (WAPCs) (box 12.1). The variety of control mechanisms used in Australia is largely historical, reflecting the various state-based arrangements that existed before the AER assumed responsibility for the regulation of distribution networks.

The choice of control mechanism has important implications for:

- the incentives of network businesses to set cost-reflective prices
- the ability of network businesses to recover more than the maximum allowable revenue
- the introduction of pricing reforms recommended in chapter 11
- the incentives for network businesses to pursue demand management

- the stability of prices from year to year
- whether network businesses or customers bear the pricing risk associated with changes in demand.

In respect of some of these issues, a lack of data means that it is unclear how large an impact the choice of control mechanism will make. It is also unclear how the pricing behaviour of network businesses would change with the widespread use of smart metering technology and the deregulation of retail prices. As a result, it is unsurprising that there is no clear consensus on the most appropriate control mechanism for electricity networks. For instance, the AER (2012a) has proposed to use revenue caps in the next regulatory period for distribution businesses in New South Wales and the ACT, whereas the AEMC (2012u) has endorsed the continuation of WAPCs.[1]

In the draft report, the Commission recommended that the revenue of all distribution businesses be regulated using WAPCs. Participants submitted a range of responses to the draft recommendation, with some in favour of it and some against (box 12.2).

After reviewing this matter, the Commission is now unconvinced that the efficiency gains associated with network pricing under a WAPC are sufficiently large to overcome other concerns, particularly as the Commission envisages pricing reform being driven through the AER approving network pricing proposals (chapter 11).[2] The Commission now considers that, while both control mechanisms have their advantages and disadvantages, on balance, the revenue cap is the preferable control mechanism for distribution businesses.

While this section focuses on distribution networks, many of the arguments addressed here also apply to transmission networks, which currently operate under revenue caps. In addition, the potential introduction of the AEMC's optional firm access package will add complexity to the operations of transmission networks. As such, substantial changes to the control mechanism applying to transmission businesses are not warranted at this time.

1 This issue has previously been considered by IPART (2001) and the Essential Services Commission of Victoria (ESC 2004b).

2 The major argument in favour of WAPCs is the incentives that they provide, in theory, for network businesses to set 'efficient' prices. If the AER were to play an active role in setting prices (as the Commission proposes in chapter 11), prices would be set at an efficient level under either a WAPC or a revenue cap. As a result, the incremental efficiency gains under a WAPC would be smaller.

Box 12.1 **The different revenue control mechanisms in Australia**

The control mechanisms used in the National Electricity Market are revenue caps, weighted average price caps (WAPCs) and maximum average revenue caps.

A revenue cap sets the maximum allowable revenue for each year of the regulatory control period. To comply with this revenue constraint, a business forecasts demand across different services for the next regulatory year and sets prices so that the expected revenue is less than or equal to the revenue cap. The business can recover more or less than the allowed amount, but knows that the maximum allowable revenue in future years will be adjusted for any difference between the expected and actual revenue of previous years (using an 'unders' and 'overs' account). Revenue caps apply to all transmission businesses in the National Electricity Market, as well as to distribution businesses in Queensland and Tasmania.

A WAPC constrains the way that network businesses are allowed to adjust network tariffs. Network businesses can adjust their tariffs to increase network revenue provided that they do not violate the following formula:

$$\frac{\sum_{i=1}^{m}\sum_{j=1}^{n}(p_t^{ij}\cdot q_{t-2}^{ij})}{\sum_{i=1}^{m}\sum_{j=1}^{n}(p_{t-1}^{ij}\cdot q_{t-2}^{ij})} \leq (1+\ \Delta CPI)(1+X_t)$$

where:

p_t = the proposed prices for the upcoming year

p_{t-1} = prices for the current year

q_{t-2} = volume quantities for the most recently completed year

X_t = the allowed real average price increase

Δ CPI = the most recent change in CPI

And the double summation signifies that the WAPC formula is calculated across both tariffs and tariff classes.

Under a WAPC, some prices can rise while others fall, as long as the average change, weighted by the quantity of the service sold, does not exceed the regulated rise in prices. These weights, which are based on actual demand from the previous period, can apply to different parts of the tariff schedule, such as the number of customers who pay a fixed charge or the quantity of electricity sold in the second block of a block tariff. The revenue recovered under a WAPC is also influenced by the estimate of demand increase made at the time of a revenue determination. If demand turns out to be more (less) than expected, the network business will receive more (less) than the target. WAPCs apply to distribution businesses in New South Wales, Victoria and South Australia.

The sole distribution business in the ACT operates under a maximum average revenue cap, which puts an upper limit on the average revenue per unit (usually kWh) of electricity sold. That average is calculated by dividing the maximum allowable revenue by the quantity of energy demanded from the most recent year available.

In a preliminary ruling, the AER has opted to use revenue caps for distribution businesses in the next regulatory period in New South Wales and the ACT (AER 2012n).

Box 12.2 **Particip ants' views on revenue control mechanisms**

Several participants preferred revenue caps:

> Since … revenue caps are almost a prerequisite for the enthusiastic adoption of demand management and energy efficiency by utilities, and the usual arguments against adopting revenue caps do not apply, we suggest that the Commission review its recommendations with a view to mandating revenue caps for those network businesses to which they do not yet apply. (EnerNOC, sub. DR83, p. 8)
>
> [Revenue caps] have some other advantages. They leave the consumers and the businesses much less exposed to errors in forecasting of energy consumption, as price caps do at the moment … The weighted average price cap does have some theoretical appeal in terms of the businesses adjusting the weights within tariffs to get an economically efficient outcome. Frankly, we haven't seen the evidence that the businesses are as sophisticated with their pricing as to take advantage of those theoretical benefits. Consequently our inclination is towards a revenue cap to deal with those things such as the forecasting errors and the opportunity for innovation in tariff design because we're really not seeing the theoretical advantages being exploited. (AER, trans., pp. 134-35)
>
> The MEU does not support this recommendation and is unsure why price caps should be mandated. As a matter of principle, price caps encourage networks to seek to increase consumption of electricity as this increases their revenue above the revenue determined by the regulator to be efficient. (Major Energy Users, sub. DR66, p. 42)

Several participants preferred weighted average price caps:

> We agree with recommendation 12.1 that "…revenues from all distribution network 'standard control services' should be subject to regulated weighted average price (not revenue) caps" on the basis of strong evidence that efficient pricing is enabled under a weighted average price cap … and is (at best) non-existent under a revenue cap. (NSW Distribution Network Service Providers, sub. DR85, attachment A, p. 4)
>
> We agree with the draft recommendation that distribution network revenue regulation should be subject to weighted average price (not revenue) caps. (EnergyAustralia, sub. DR82, p. 6)
>
> A true productivity-based approach, combined with allowed pricing flexibility for distributors, would create powerful incentives for energy utilities to price efficiently to maximise their profits. Glomming revenue caps onto a cost-based building block regulatory model would do nothing to rectify the underlying deficiencies of that approach. (Pacific Economics Group, sub. DR107, p. 1)

Other participants did not express a strong preference, highlighting that the choice of control mechanism will reflect the weight given to different factors:

> It's very much a sort of risk trade-off from the regulator's point of view, a view about forecasts, a view about risks of under recovery and over-recovery, so all of the sort of factors which the national electricity objective directs them toward. We're just sort of agnostic on this issue. (Electricity Networks Association, trans., p. 346)

The remainder of this section discusses the criteria relevant to the choice between revenue caps and WAPCs.

The incentive to set efficient prices

It is generally considered that, in theory at least, a WAPC provides a greater incentive than a revenue cap for network businesses to set efficient prices (AEMC 2012u, p. 218; AER 2012n, p. 57; Ausgrid 2012a, p. 9).[3] However, there are different interpretations of what 'efficient pricing' is, with cost-reflective pricing being just one interpretation.

A revenue cap guarantees network businesses a particular level of revenue, subject to meeting reliability requirements. As such, the network business cannot earn extra revenue by adjusting prices. It may be able to reduce its costs of augmentation by increasing prices in congested areas, but in practice, network businesses operating under a revenue cap have historically tended to use relatively passive pricing strategies. (NSW DNSPs 2012, p. 46).

In contrast, under a WAPC, network businesses are able to readjust tariffs to increase the revenue they recover. For instance, a network business can increase the tariffs on customers with inelastic demand, while decreasing tariffs on customers with elastic demand. Such readjustment can also happen across different types of tariffs being charged to the same customer. For instance, the network business may increase the fixed charge (which is relatively demand inelastic) and decrease the variable charge (which is more demand elastic). Network businesses can also set prices higher in congested areas to avoid the cost of augmentation — trading off the lower costs of operating the network against the lower revenue they receive as a result of reducing demand. Setting tariffs in these ways (so-called Ramsey Pricing) is an efficient way of recovering network costs.[4]

However, a network business may also increase revenues under a WAPC by increasing tariffs for particular services that are experiencing sales growth within a regulatory period. As explained by the AER:

> … during the regulatory control period DNSPs were able to make windfall gains by increasing the price (above the general increase specified in the WAPC) of components of particular services experiencing sales growth above its forecast. (2012n, p. 128)

It is unclear whether such tariff rebalancing results in more efficient pricing. Unexpected growth in demand may result in a higher likelihood of network congestion and network augmentation. In such a case, a higher network charge may be efficient, as it would reduce demand and relieve congestion on the network. However, if the

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3 In contrast, EnerNOC argued that, although the theoretical reasoning behind WAPCs is sound, it does not apply to Australian distribution networks, as almost all distributors' costs are fixed within the five year regulatory period (sub. DR83, p. 5).

4 While efficient, Ramsey pricing is sometimes criticized for its equity implications (Bhattacharyya 2011).

increased growth in demand triggers a network augmentation, resulting in additional network capacity, a WAPC would still encourage network businesses to set a high price, which would reduce demand on an already uncongested network and, therefore, not be efficient (at least over the short term).

The compatibility of revenue caps and WAPCs with short-run marginal cost and long-run marginal cost pricing, including the Commission's pricing proposals in chapter 11, are discussed later in this section.

Is there evidence of more efficient pricing under weighted average price caps?

It is unclear whether the theoretical incentives to set prices more efficiently under a WAPC have translated in practice into more efficient prices. The AER found that the theoretical incentives for efficient pricing were not observed in practice (2012n, p. 47).[5] However, the NSW DNSPs (2012, p. 46) noted that distributors currently facing revenue caps (in Queensland, Tasmania and the ACT) have priced purely on flat tariffs, whereas the majority of other distributors, who face WAPCs, have used (non time-based) block tariffs and are moving towards time of use pricing. Similarly, Ausgrid (2012a) noted that changes to their tariffs, to be more reflective of costs, were an outcome of the WAPC and that they would not have responded in this way under a revenue cap (pp. 11-13).

The Commission considers that while there is evidence of more proactive pricing policies from network businesses under WAPCs, there is very little evidence that this has resulted in more efficient pricing. It agrees with the AER that the use of block tariffs is not, in itself, evidence of more efficient pricing (AER 2012a, p. 18).

The lack of evidence of more efficient pricing under a WAPC may largely be attributed to the absence of smart meters, along with the influence of state and territory governments on a network business's pricing proposals to the AER. As a result, it is difficult to draw a strong conclusion about how WAPCs may operate in the future, if smart meters become more widespread and state and territory governments have less direct influence over the operation of electricity networks.

Over-recovery of revenue

Under a revenue cap, distribution businesses know at the beginning of a regulatory period how much revenue they are to receive. If they recover more or less than this

5 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.

amount in a given year, then the revenue they are allowed to recover in a future year will be adjusted accordingly. This provides relative certainty that they will be able to recover the efficient costs of maintaining and operating the network, which will vary only slightly with demand over the short term.

In contrast, WAPCs provide network businesses with financial incentives to adjust their tariffs. As a result, the amount of revenue that is recovered varies from year to year and, in general, will tend to allow network businesses to recover more than the maximum allowable revenue calculated during the building block process.

In addition to the ways noted earlier in which a network business can adjust tariffs to increase revenues, WAPCs also allow the network business a greater opportunity to game the regulatory system. WAPCs create incentives for network businesses to be conservative when forecasting average demand, such that they consistently err on the side of underestimating average demand. This will result in a higher WAPC and higher levels of recovered revenue. If actual demand turns out to be higher than the conservative forecast, then network businesses are able to recover more than the maximum allowable revenue.

This is consistent with the incentives discussed in chapter 5 to overestimate demand forecasts for the purposes of approving capital expenditure (capex) proposals. Capex forecasts are heavily influenced by peak demand forecasts, while WAPCs are based on forecasts of average demand. Thus, it is in the financial interests of a network business to underestimate average demand while overestimating peak demand.

Given the incentive for network businesses to underestimate average demand forecasts, their estimates are carefully scrutinised by the AER. However, it is likely that a slightly conservative demand forecast would still be considered to fall within a reasonable bound of accuracy and be accepted by the AER. This reflects a more general point that, under a WAPC, demand forecasts become more important as well as more complicated, because the AER must assess the accuracy of forecasts across all tariffs rather than just the accuracy of peak demand forecasts.

Is there evidence that network businesses recover more than the maximum allowable revenue under a weighted average price cap?

Some participants have suggested that network businesses operating under WAPCs have been able to systematically recover more revenue than the maximum allowable revenue calculated using the building block process. For example, the AER said that:

> While the AER rigorously tests the forecasts proposed by the DNSPs, actual data for DNSPs with WAPCs (compared with the forecast data on which the WAPCs have been set) show actual sales volumes often, and perhaps consistently, exceed forecasts. (2012a, p. 11)

The AER also pointed out that in the 2006–10 regulatory control period, Victorian distribution businesses (under a WAPC) recovered $568 million, or 8.28 per cent more than the maximum allowable revenue (AER 2012n, p. 128).

Further analysis performed by the AER suggests that over-recovery of revenue under a WAPC is common, although given the limited history of WAPCs and the various jurisdictions in which they operated, it is difficult to distinguish the extent to which network businesses are able to over-recover revenue in the long run. It is also difficult to separate the impact of demand forecast errors and tariff restructuring on the total level of revenue over-recovery.[6]

Incentive effects of over-recovery on investment decisions

As well as leading to higher network costs directly, over-recovery of revenue under a WAPC may indirectly give a network business an incentive to overinvest in its network. If a network business knows with reasonable certainty that it will be able to over-recover revenue in the long term, it will have a similar incentive to that arising from an overestimated weighted average cost of capital (an issue discussed in section 5.3). A network business may overinvest in network assets, knowing that when it recovers funds through the return on investment and depreciation allowance, it is likely to receive additional funds.

The extent to which there is an incentive to overinvest depends on how much revenue a network business can gain by adjusting its tariffs, which as discussed above, is difficult to determine. However, if networks were confident of recovering 2 per cent more than the maximum allowable revenue over the long term (a not inconceivable number), it would seriously undermine the incentives for network businesses to reduce expenditure.

Are the gains from efficient pricing under weighted average price caps worth the higher prices?

A WAPC, at least in theory, provides financial incentives to set prices more efficiently, and in doing so allows the network business to recover more than the maximum allowable revenue calculated using the building block approach. This is

6 AER, pers. comm., 26 Feb 2013.

not necessarily a problem. For instance, if the gains from more efficient pricing outweigh the costs of having higher network charges this would be seen as worthwhile, and can even be characterised as an extension of the incentive regulation framework.

However, based on the evidence discussed above, the use of WAPCs has resulted in (some cases quite significant) increases in network prices, with only minimal evidence of improvement in pricing efficiency. This suggests that it is highly unlikely that pricing efficiencies achieved under WAPCs have been worthwhile. Nevertheless, as discussed previously, it is not clear whether this would be true in the future, if smart metering technology were more widely available and state governments had less influence over the price setting process.

Other factors that influence the choice of revenue control mechanism

The Commission considers that the incentives to set efficient prices and the over-recovery of revenue are the main considerations affecting the choice between revenue caps and WAPCs. However, there are other criteria, some raised by participants, that are also relevant.

Compatibility with the Commission's pricing proposals in chapter 11

The Commission notes that, while WAPCs provide some incentive to set cost-reflective prices, neither WAPCs nor revenue caps provide network businesses an incentive to set prices at long-run marginal cost. Therefore, in order to achieve cost-reflective prices based on long-run marginal cost in the National Electricity Market (NEM), it is necessary to regulate prices directly, rather than relying on network driven pricing reform.

In chapter 11, the Commission has proposed cost-reflective, time-based pricing for distribution network services, predicated on the long-run marginal costs of meeting peak demand. The Commission has recommended that this should be implemented through the Standing Council on Energy and Resources (SCER) and involve, among other things, changes to the National Electricity Rules and the development by the AER of relevant guidelines (recommendations 11.1-9).

Cost-reflective pricing, as proposed by the Commission, is likely to be easier to implement in conjunction with revenue caps, rather than WAPCs. This is because the weights used in a WAPC are normally calculated using historical demand data. In any major restructuring of tariffs, such as the wide-scale introduction of critical peak pricing, relevant historical demand estimates would not be available and the weights used in the WAPC would have to be estimated.[7] These estimates would have large financial implications, with the network businesses motivated to push for low demand forecasts in order to receive approval for higher prices.

The incentive to underestimate future demand does not exist under a revenue cap. While cost-reflective pricing will require detailed demand estimates, there is no financial incentive under revenue caps to bias the estimate. As such, there is a better chance of both the network business and the AER approaching this task without a predetermined agenda.

Compatibility with demand management

In general, network businesses under WAPCs would not have an incentive to reduce demand, as this would reduce their revenue. This is not true of revenue caps, which guarantee the revenue that a network business can recover even if a demand management program successfully reduces demand within a period. As such, many participants have favoured revenue caps for their compatibility with demand management (AER 2012n, p. 61; EnerNOC, sub. DR83). Several governments, such as those in the United States, have moved towards revenue caps for this reason (NARUC 2007, p. 8).[8]

Recognising this aspect of WAPCs, the AER administers a scheme — the demand management and embedded generation connection incentive scheme (DMEGCIS) — 'part B' of which is designed to compensate distribution businesses under WAPCs for any revenue they forego from undertaking cost-effective non-tariff based demand management.

Given the scheme's objectives, network businesses should have incentives to pursue demand management programs that are broadly equivalent under either a WAPC or a revenue cap. However, as discussed in section 12.2, there is some contention about the effectiveness of the scheme. In particular, the AER has previously expressed concern regarding the high degree of complexity of the foregone revenue calculations. (AER 2012g, p. 14).

7 This task will be made more difficult by the need to estimate demand response under the new tariff schedule.

8 Although, given the different regulatory structures employed around the world, it is difficult to draw strong conclusions regarding the success of different control mechanisms.

Pricing stability

Highly volatile prices are undesirable for two main reasons. First, customers generally want to have stable (and low) electricity prices and wish to avoid 'bill shock'. Second, prices that vary substantially are unlikely to be consistent with long-run marginal cost pricing, which is the Commission's preferred methodology for calculating network prices (chapter 11).

Both revenue caps and WAPCs can introduce pricing volatility, but in different ways.

Under a revenue cap, prices are adjusted each year based on the 'unders and overs account', which is determined by revenue collected in the previous year and has no connection to demand in the upcoming year. For example, if demand is unexpectedly high (perhaps due to a persistently hot summer), then a network business would recover more than its allowable revenue. In subsequent years, prices would be reduced to compensate for this over-recovery.

If this type of pricing variability proves to be too volatile, it could be smoothed by allowing the unders and overs account to be depleted over a longer period. The AER's current methods of applying revenue caps take some steps to smooth out the pricing variability.[9] These methods could be amended (if considered desirable) to enable smoothing over a longer period (which could exceed the current five year regulatory period).

Under a WAPC, prices are susceptible to large jumps at the end of the regulatory period. This occurs because the demand forecasts used to set the annual adjustments in the WAPC are only made every five years as part of the regulatory determination process. Therefore, if actual demand is different from forecast demand, prices cannot be corrected until the end of the regulatory period, at which point there can be a large price adjustment. In contrast, under a revenue cap, demand forecasts are updated annually, which lowers the likelihood of large, one-off movements at the end of the regulatory period. (AER 2012n, p. 59)

WAPCs also introduce variability to customer tariffs because, as discussed above, they are designed to encourage network businesses to adjust tariffs within a regulatory period. For example, table 12.1 shows the annual adjustments in tariffs paid by Ausgrid's medium business customers. While this is only a single example

[9] For instance, in Queensland, a variance between expected and recovered revenue of less than 2 per cent is recovered in one year, a variance between 2 and 5 per cent is recovered over two years and a variance greater than 5 per cent must be recovered based on a 'clearly documented plan' submitted to the AER.

and does not provide any information about how common such tariff adjustment is, it does highlight the types of adjustments that are encouraged under a WAPC.[10]

Table 12.1 **Variability of tariffs under weighted average price caps**
Tariffs applied to medium business customers by Ausgrid[a]

Change in charge from previous year	*2010-11*	*2011-12*	*2012-13*
	Per cent	Per cent	Per cent
Fixed charge	40.3	98.4	175.0
Peak energy charge	28.1	9.0	117.0
Shoulder energy charge	10.5	27.8	8.7
Off-peak energy charge	-48.7	44.7	37.0
Peak capacity charge	43.4	94.1	18.5

[a] Tariff class EA302 applied to medium business customers on time of use tariffs.
Source: AER (2013d).

In summary, both revenue and WAPCs introduce network pricing instability, but they do so in different ways. It is not clear which control mechanism will have a larger impact on customers. As such, it should not be a major consideration in choosing between them.

Who bears the risk of high or low demand?

Several participants have suggested that identifying the party bearing the pricing risk from changes in demand is an important criterion for choosing an appropriate control mechanism (Ausgrid 2012a, p. 15; EnerNOC, sub. DR83, p. 7; Essential Energy 2012, p. 4).

Under a WAPC, network revenues fluctuate based on actual demand, while in the short term, the efficient costs of meeting demand vary only slightly with demand. As a result, network businesses are exposed to the risk of short-term demand fluctuations. In years of high demand, a network business will receive more revenue and, therefore, more profits than forecast. In periods of low demand, a network business will recover less revenue and may make a loss.

In contrast, under a revenue cap, the risk of high or low electricity prices is borne by consumers. This occurs because total network revenue is fixed under a revenue cap and, if average demand decreases (increases), the average price will rise (fall) to keep revenue stable.

10 It is unlikely that these tariff adjustments have resulted in a more efficient pricing structure.

Where demand changes, pricing risks arise and must be borne by either network businesses or customers. As discussed in chapter 5, incentive regulation aims to place risks with network businesses where they are able to manage that risk.[11] Where network businesses are unable to manage risks, they should pass this exposure on to consumers (as is the case with a revenue cap), where at least the risk is diversified by spreading it out across a wider group. This also allows network businesses to achieve stable returns and access low borrowing costs.

Summing up

The choice between revenue caps and WAPCs is not clear cut (table 12.2). Indeed, experienced and knowledgeable stakeholders disagree on the ideal choice of control mechanism.

Table 12.2 **The choice between revenue control mechanisms**

	Weighted average price caps	*Revenue caps*
Theoretical incentives for efficient pricing?	Yes, but little evidence that efficient pricing occurs in practice.	Poor incentives
Revenue over-recovery?	Yes	No, as revenue is controlled.
Compatible with the PC's pricing proposals in chapter 11?	Scope for gaming demand forecasts.	Yes
Compatible with demand management?	Yes, but only if the demand management and embedded connection incentive scheme works as intended (see later).	Yes
Pricing fluctuations?	Yes, moderate	Yes, moderate
Who bears demand risk?	Network businesses	Consumers

WAPCs theoretically provide network businesses with an incentive to set cost-reflective network prices, although it is unclear the extent to which this might translate into efficient pricing decisions in practice. They also provide network businesses with an ability to over-recover revenue, which will result in transfers from customers to network businesses and weaken the incentive for network businesses to control their expenditure.

11 For instance, cost pass throughs are permitted where network businesses are unable to influence the likelihood or costs involved, such as for tax changes and price rises of some large inputs, but they are not allowed where the network business can control the costs, such as the costs of construction or the cost of capital.

Revenue caps remove the ability of network businesses to over-recover revenue and provide them with a more stable source of long-term profits. They are more compatible, than WAPCs, with demand management options and the Commission's pricing recommendations in chapter 11. Revenue caps are also less reliant on accurate demand forecasts than WAPCs.

In the Commission's view, the major consideration is whether the incentives to set prices efficiently under a WAPC are sufficient to compensate for the additional revenue that can be recovered under the cap. While there may be some efficiency gains associated with WAPCs, they are likely to be small compared with the increased revenue that can be recovered. Therefore, the Commission agrees with the AER, that on balance, revenue caps are the more appropriate control mechanism for distribution businesses.

RECOMMENDATION 12.1

The Australian Energy Regulator should use revenue caps, rather than weighted average price caps, in the regulation of all distribution businesses.

12.2 The incentives of network businesses to undertake demand management

In operating their networks, network businesses must decide between investing in physical assets and undertaking non-network alternatives, such as demand management projects and embedded generation. Ideally, network businesses will face an unbiased decision between network investment and other alternatives, with the profit maximising interests of network businesses coinciding with the long-run interests of consumers.

However, there are several reasons why, at present, the network business's decision might be skewed unduly towards undertaking network investments. These include that capital expenditure is automatically rolled into the regulatory asset base at the end of the regulatory period, or that capital expenditure is unduly compensated through an artificially high WACC. It is also possible that state-owned network businesses may over-invest in capital expenditure to profit from low public borrowing costs (chapter 5).

The Commission has suggested a number of reforms to correct this underlying bias towards capital investment including:

- measures to improve the accuracy of the regulatory WACC

- the introduction of an efficiency benefits sharing scheme to ensure that network businesses earn an equal return from reductions in capital or in operating expenditure
- an ex post review mechanism that can be used to assess the efficiency of capital expenditure before it is rolled in to the regulatory asset base
- privatisation of state-owned network businesses.

Even if these reforms were implemented, the regulatory structure may still favour the construction of physical assets over non-network solutions such as demand management. This is because:

- demand management is still a relatively new development, with some debate about its effectiveness and appropriate design
- the use of demand management in distribution networks provides spillover benefits, including reduced costs in the transmission network and wholesale electricity market, which a network business is unlikely to consider when making its investment decision
- under a WAPC, network businesses have a reduced incentive to use demand management as it will result in less demand and, therefore, less revenue.

To address the concern that the regulatory design favours physical assets over non-network options, the AER operates the demand management and embedded generation connection incentive scheme (DMEGCIS). This scheme is not meant to be the primary source of recovery of demand management expenditure. Rather, it is intended to complement the incentive regulation structure and correct any disincentives that might discourage network businesses from undertaking demand management. While the Rules allow the AER discretion about how it applies the DMEGCIS, to date it has applied the scheme in a narrow manner, which currently includes two parts:

- Part A is an innovation allowance (called ‘the Demand Management Innovation Allowance’) that provides a modest level of funding to network businesses to undertake demand management.
- Part B is a payment designed to neutralise incentives which otherwise exist under a WAPC to maintain or, indeed, increase levels of demand.

In its recently completed Power of Choice review (AEMC 2012u), the AEMC recommended a number of possible changes to the DMEGCIS, while leaving the detailed design and implementation of the scheme to the AER.

The remainder of this section considers these and other changes to the scheme that the Productivity Commission considers would be desirable.

The value of information and innovation

The innovation allowance provides funding to network businesses to trial innovative demand management schemes that they would otherwise have been unable to fund. Such trials provide information for the network business and the regulator to better calculate the efficient level of demand management in the NEM. To date, the innovation allowance has been relatively small, totalling no more than $1 million per year for each distribution business.

The appropriate scope and magnitude of the innovation allowance has been debated. On the one hand, increasing the use of cost-reflective pricing in the NEM will require information, gained through trials and experimentation, which could be funded by the innovation allowance. For instance, information will be required to:

- accurately assess the costs and benefits of smart meters
- support the functions set out in recommendations 11.5 and 11.6, which include the AER approving reasonable forward-looking forecasts of peak demand and estimates of the long-run marginal cost of peak capacity, and modelling the demand responsiveness of end-users to cost-reflective pricing.

On the other hand, if other changes to the DMEGCIS (such as those discussed below) result in a significant increase in commercially viable demand management, there is less justification for the innovation allowance.

The Commission considers that in the short term, unless other changes are made to the DMEGCIS to encourage demand management, the innovation allowance should be increased. This view has been supported by several network businesses (Ausgrid 2012f; CitiPower et al., sub. DR90).

The Commission also considers that the innovation allowance should fund 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.
- 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 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 often be critical to the success of the trials.

- Final payment would require that the AER receive all data, which should then be 'de-identified' 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.

Beneficial spill-overs

Demand management initiatives undertaken by distribution businesses may also lead to reduced costs in the transmission network and wholesale electricity market. As the distribution business does not get rewarded for these effects, it is likely that some demand management projects would not be provided by distribution businesses where it would be socially beneficial to do so.

In its Power of Choice review (AEMC 2012u), the AEMC recommended an incentive payment be incorporated in the DMEGCIS that provides network businesses with a share of the beneficial spillovers from demand management.

The Commission notes that the AEMC also recommended that these benefits should be calculated on a project-by-project basis. This is likely to be both difficult and costly in practice. An alternative is for the AER to calculate the average spillover from a sample of demand management projects and use this as the basis for the incentive payment for all projects. While this might lead to less accurate estimates, it would improve the incentives to undertake demand management compared with the status quo and may prove to be a more cost effective way to implement such payments.

Correcting for incentives under a weighted average price cap

As discussed earlier, network businesses operating under a WAPC do not naturally have an incentive to undertake demand management, as this would result in lower revenues. To correct this, part B of the DMEGCIS is intended to compensate network businesses when demand has been reduced as the result of an approved demand management project.

However, some participants criticised the administration of this aspect of the scheme. For example, EnerNOC described the process as:

> … 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)

The AER has also expressed concern regarding the complexity of the scheme (AER 2012g, p. 14).

The Commission notes that moving to revenue caps (recommendation 12.1) will make this part of the scheme redundant.

Are further measures needed?

As noted earlier, along with the above changes to the DMEGCIS, there are several recommendations in this report (for example, the introduction of an efficiency benefit sharing scheme and changes in the WACC framework) that would improve the incentives for network businesses to undertake demand management by removing regulatory biases towards capital investment.

However, if the implementation of the Commission's recommendations were to significantly fall behind schedule, or if there was evidence that opportunities for efficient demand management were being forgone by network businesses, the AER should investigate expanding the scope of the DMEGCIS to provide network businesses with additional incentive payments or penalties.

12.3 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)
- efficient IT and billing systems
- 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 who 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, which reduces the price advantages for consumers who are willing to curtail their peak demand use
- smart meters are mostly not available to facilitate more innovative time of use 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 businesses 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 regulation and the removal of compulsory default retail schemes that effectively place a cap on prices offered in the jurisdiction. The case for this reform and how it might be accelerated is discussed immediately below. The following sub-section then assesses how the behaviour of retailers would be expected to change.

Retail price regulation

State and territory governments introduced retail price regulation for electricity as an adjunct to the deregulation of integrated monopoly services, with the intention that it be 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 retail price regulation as an *interim* tool is not debated. However, once contestability between retailers is achieved, retail price regulation has little role to play, with competition among retailers serving consumers' interests most appropriately and keeping retail margins 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 and innovation, which ultimately leads to inferior outcomes for consumers (AGL Energy, sub. DR86, attachment; Energy Retailers Association of Australia, sub. DR76; Origin Energy, sub. DR64).

Accordingly, the Commission, along with many others, has previously advocated the removal of retail price regulation for electricity, recognising its inconsistency with the long-term interests of consumers (for example, PC 2008, 2012b; DRET 2011).

To date, only Victoria and, just recently, South Australia have removed retail price regulation for electricity, despite COAG having agreed in 2006 to a process for its removal, subject to assessment of retail contestability in each jurisdiction by the AEMC. (The slow progress in deregulating retail prices is discussed later).

Regulated retail prices are set by state and territory regulators under delegation from the relevant Minister. The regulated 'standing offer' or a 'notified' price is then required to be available to residential and some smaller business consumers.[12] Consumers can choose to purchase (unregulated) market offers, although these are effectively '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 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, if the regulated standing offer price is held below costs, the likelihood of a vibrant retail market is significantly reduced. Incumbent retailers are then also likely to exit the market.

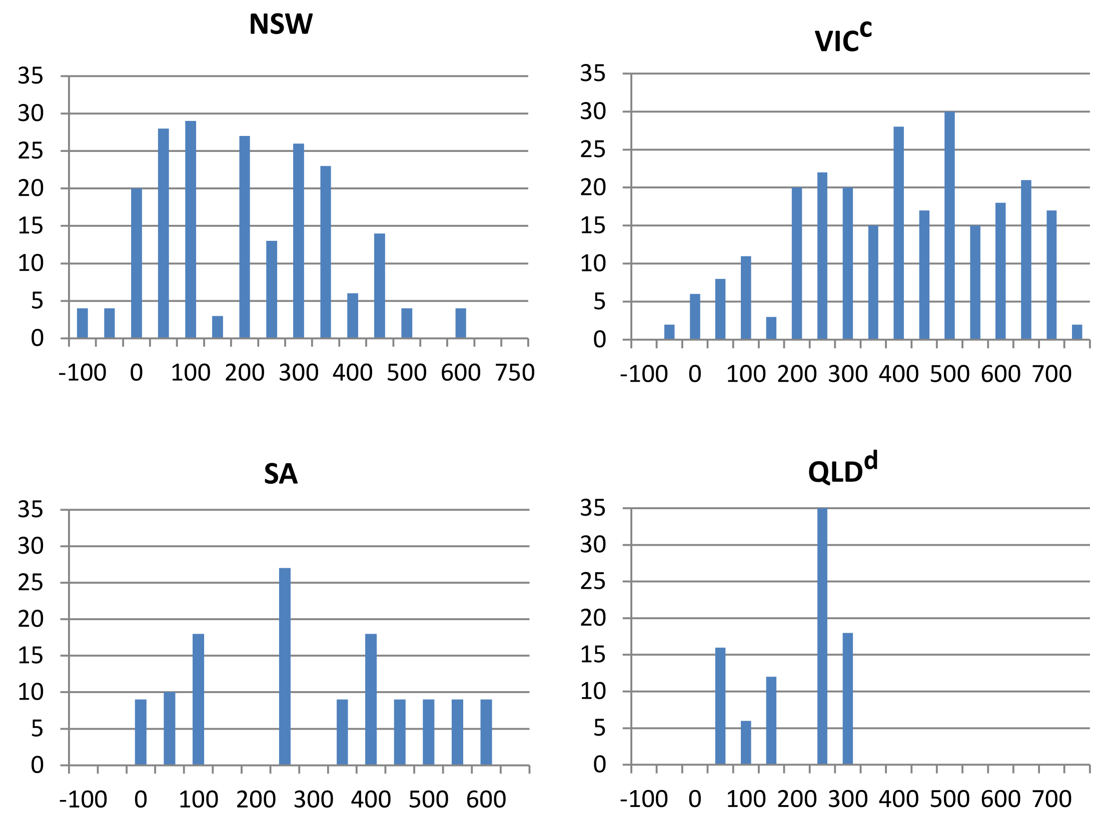
The dependency between the regulated and unregulated product is reinforced by some consumers' perceptions that a control on prices signals a 'good deal', discouraging them from 'switching' to a potentially cheaper market offer. (A lack of switching or customer inertia can further stifle competitive outcomes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

12 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 or territory 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 (Plumb and Davis 2010). The phasing out of retail price regulation has usually commenced with large business customers, followed by small to medium business customers (a change recently signalled to occur in New South Wales (Macdonald-Smith 2012). Residential customers are usually the last customer segment reviewed.

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 currently 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 one analysis has found that lower-income consumers are significantly over-represented among those on the more costly regulated retail product (ESCOSA 2006).

Figure 12.1 **Annual savings from market offers**[a]

Frequency of offers (vertical-axis) by category of annual dollar savings (horizontal axis) when compared with 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 2100 kWh. [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/.

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 the intention of the freeze was to lower the cost of living, it does not serve consumers' interests well in the longer term. Rather than imposing retail price regulation, governments need to address the underlying cost pressures on prices — including by implementing the suite of measures proposed in this report.

Because retail price regulation hinders the development of a competitive retail market, its removal may initially increase prices 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 removing retail price regulation in jurisdictions where it has prevented a competitive retail market developing. That could include the phasing out of retail price regulation by making it progressively less 'binding' over time with a view to lessening 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 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 on pricing flexibility, competition and innovation in the retail sector, which would be promoted through retail price deregulation. The benefits, while not eliminated, would be significantly smaller were retail price regulation retained.[13]

Retail price regulation prevents consumers from 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 time-based network charges, 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.

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 in home consumption information, warn customers in advance of peak consumption days, warn customers about bills exceeding a pre-agreed threshold

[13] In its Power of Choice review, the AEMC was cautious about the impact of removing retail pricing regulation on retailers' pricing flexibility:

> We are not convinced that simply removing pricing regulation will result in all retailers offering a wide range of DSP [demand side participation] products to consumers. Under the existing arrangements in states which have retail contestability, retailers are already able to provide diverse market offers, including innovative DSP related tariffs to retail consumers.
>
> While we do not agree that retail price regulation per se should discourage retailers from introducing flexible prices (provided sufficient headroom is allowed for in regulated prices), we do consider that price regulation could add to compliance costs and reduces flexibility for retailers. (2012u, pp. 194-5)

The Productivity Commission agrees that the presence of retail contestability creates pressures on retailers to offer innovative and flexible tariffs to customers, even if there is retail price regulation with sufficient headroom. However, retailers' pricing flexibility is likely to be much greater under deregulation.

in a billing cycle, and, where desired by consumers, facilitate load control services, or automate other aspects of electricity use.

Price regulation applied to a time-based tariff would be complex and costly for state and territory regulators to administer in order to avoid locking-in cross-subsidies for peaky users (box 12.3). 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.

Accelerating retail price deregulation

COAG agreed in 2006 to a process of phasing out retail price regulation for both electricity and natural gas where ‘effective retail competition can be demonstrated’ by the AEMC (box 12.4).

However, progress under the COAG process has been very slow and, in the absence of change, is likely to continue to be so.

- To date, the AEMC has completed reviews of retail competition in only three jurisdictions — Victoria (in 2007), South Australia (in 2008) and the ACT (2011) — and recommended the removal of retail price regulation, accompanied by the implementation of consumer awareness and price monitoring measures in each case (box 12.4). The Victorian Government responded by removing its retail price regulation in 2009. The South Australia Government initially rejected the AEMC’s advice, but deregulated its retail prices some four years later in February 2013. The ACT Government rejected the AEMC’s advice and decided to retain its retail price regulation for a further two years (until 2013), due to concerns that the removal of retail price regulation would lead to increases in electricity prices.
- Although there is a timetable for AEMC reviews of jurisdictions with retail price regulation, even were the reviews to proceed as scheduled, they would not all be completed before 2016. Further, COAG’s December 2012 implementation plan for energy market reform does no more than require those state and territory governments with retail price regulation to report to SCER by the end of 2013 on clear transition plans to price deregulation, among other things.

Box 12.3 **The impracticality of regulating a time-based retail price**

It would be very challenging for a regulator 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 full 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 at which 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 to 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.

Box 12.4 **What progress has been made in phasing out retail price regulation?**

COAG agreed in 2006 to a process for phasing out retail price regulation for electricity and natural gas where 'effective retail competition can be demonstrated' (Australian Energy Market Agreement, clauses 14.10–17). The AEMC is tasked with assessing the effectiveness of retail competition in each jurisdiction (apart from Western Australia being outside of the NEM). If it finds that retail competition is effective, it must advise on ways to phase out retail price regulation. If it finds that competition is not effective, it must identify ways to promote the growth of effective competition. State and territory governments make the final decision on this matter. The AEMC reviews are conducted according to a schedule determined by the MCE (now SCER).

To date, the AEMC has completed retail competition reviews for just three jurisdictions — Victoria, South Australia and the ACT.

- In its reviews of the Victorian and South Australian energy markets in 2007 and 2008, respectively, the AEMC found competition was effective in both markets and recommended that retail price regulation be discontinued and replaced with a price monitoring regime. The Victorian Government accepted the AEMC's recommendations and removed retail price regulation on 1 January 2009. However, the South Australian Government did not accept the AEMC's recommendations; it was concerned that more than 30 per cent of small energy customers remained on standing contracts with regulated prices and that stakeholders were polarised in their views on the effectiveness of competition. It was not until 1 February 2013 that the South Australian Government deregulated retail prices.
- In its review of the ACT energy market between 2010 and 2011, the AEMC found that competition in the ACT small customer market was not effective, partly because customers were unaware of their ability to switch retailers. It recommended removing retail price controls from 1 July 2012 in conjunction with other measures such as running a consumer education campaign to increase awareness of the benefits of competition and a price monitoring regime. However, the ACT Government decided to retain retail price controls for another two years as it considered that removing them would increase the average cost of electricity, which would not benefit consumers.

The AEMC commenced a review of the New South Wales energy market in late 2012, which it is required to finalise by 30 September 2013. Further AEMC reviews are scheduled for Queensland (2013), the ACT (2016) and Tasmania (within 18 months of full retail contestability being introduced).

(Continued next page)

Box 12.4 **(continued)**

In COAG's December 2012 implementation plan for energy market reform, key recommendations on the deregulation of retail prices included that jurisdictions with retail price regulation:

- work towards effective competition where it does not exist to allow greater opportunities for innovation in, and choice of, retail offers, and to provide advice to SCER by end of 2013 on the current state of competition and policy settings to fulfil this commitment, including where appropriate, clear transition plans to price deregulation
- that have previously been advised by the AEMC to deregulate prices (namely, the ACT) to re-evaluate that advice and report back to SCER by end of 2013 on the potential to act on that advice.

In relation to Tasmania, the State Government's reforms to the electricity supply industry announced in May 2012 and expanded upon in March 2013 included the following elements:

- the introduction of full retail competition from 1 January 2014
- the sale of Aurora's retail customers in blocks to new, competing private sector retailers from or before the start of full retail competition, including:
  - the packaging of Aurora's business and residential retail customers into two bundles for sale with each bundle covering a range of local government areas
- the continuation of retail price regulation by the Tasmanian Economic Regulator until retail competition is effective
- the Tasmanian Economic Regulator being given a new objective of monitoring and reporting on the development of competition in the electricity retail market.

Sources: ACT Government (sub. DR75, p. 2); AEMC (2012x; 2011l; 2008c, d); AER (2012q; 2013a); COAG (2012); Conlon (2009); Corbell (2011); ESCOSA (2013); Green (2012, attachment); MCE and MCMPR (2011); Tasmanian Government (2013).

The capacity of state and territory governments to reject the outcomes of an AEMC review of the effectiveness of retail competition — as occurred in the case of reviews of the ACT and South Australia — is a weakness of the current COAG process.

Origin Energy suggested that once the AEMC has found competition to be effective in a jurisdiction, the onus should be placed on the relevant state or territory government to justify its decision not to remove price regulation:

> … the jurisdiction [should] be required, via an amendment to the Australian Energy Markets Agreement … to provide:
>
> - A transparent rationale for their decision not to deregulate, using evidence to identify where competition is inadequate;

- Proposed steps to be taken by the jurisdictional government to address remaining limitations in the competitive environment;
- A date within the next twelve months by which to report on progress in addressing limitations in the competitive environment as identified, with new measures proposed if required; and
- A date within the next twelve months by which time a new decision on removing price regulation will have been taken. (sub. DR64, p. 5)

The Commission considers that state and territory governments should implement their COAG commitments. A government should remove its retail price regulation of electricity as soon as practicable after the AEMC finds that retail competition in the jurisdiction is effective. The exception would be where the AEMC 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 or price monitoring measures. In that case, measures recommended by the AEMC to promote effective retail competition in a jurisdiction, including structural reforms, should be implemented by the relevant state and territory government as soon as practicable. The Commission notes that governments continue to have the opportunity to participate in an AEMC review, and to submit their own evidence on the effectiveness of competition, or on the rationale for retaining retail price regulation.

Despite the existence of a timetable of AEMC reviews and a commitment by governments to report back to SCER by 2013 on transition plans to remove price regulation, there is no tight agreed deadline for the removal of retail price regulation. The absence of a deadline can lead to further delays and procrastination.

The Commission considers that all retail price regulation should be removed by no later than 2015. Such a deadline would require accelerating the AEMC's current timetable of reviews particularly for Tasmania and the ACT.[14]

Regardless of any such deadline or timetable, retail price regulation should not apply in network regions where smart meters have been (or would soon be) rolled out and where time-based network charges could be introduced, including to business customers.

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[14] The AEMC review of Tasmania's retail market is scheduled to occur 18 months after full retail contestability is introduced in that jurisdiction. As the Tasmanian Government has announced that full retail contestability would be introduced in January 2014, an AEMC review is unlikely before July 2015. The ACT review is scheduled for 2016. However, SCER has asked the ACT Government to revisit the findings and recommendations of the AEMC's 2011 review and report back by the end of 2013.

RECOMMENDATION 12.2

State and territory governments should implement, as soon as practicable, any advice from a retail competition review by the Australian Energy Market Commission to remove retail price regulation, and/or undertake consumer awareness measures and structural reforms to improve the effectiveness of retail competition.

RECOMMENDATION 12.3

The Standing Council on Energy and Resources, in consultation with the Australian Energy Market Commission, should revise the current timetable for retail competition reviews to enable all retail price regulation to be removed no later than 2015.

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 (box 12.5). 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-based charges in their retail offers.

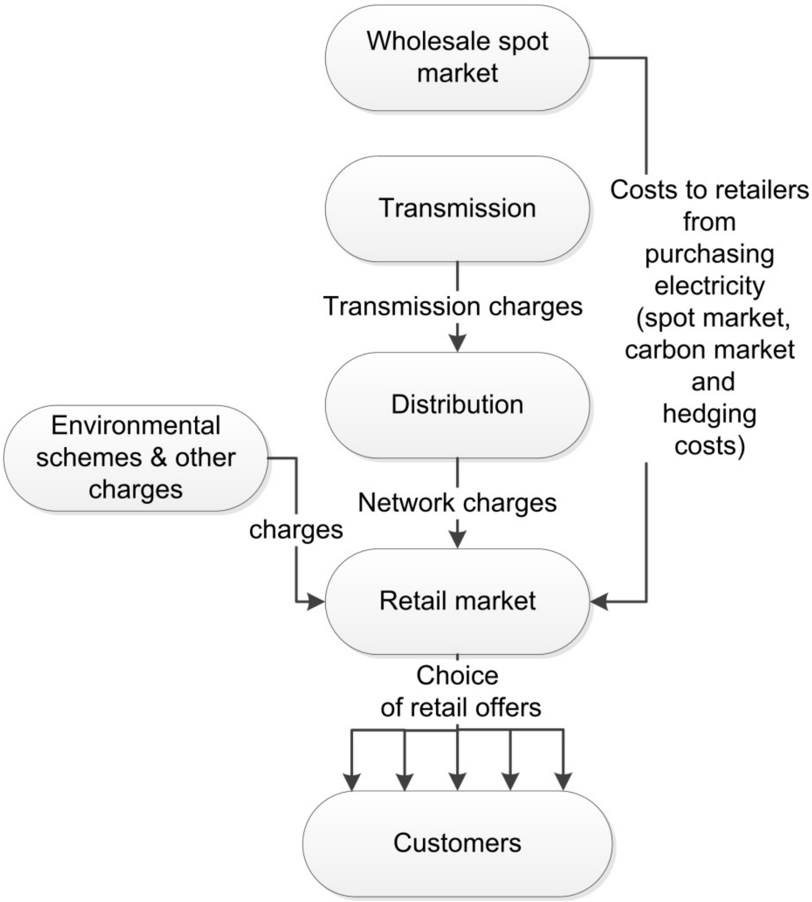
It would not be efficient (or financially sustainable) for retailers to maintain the same level of (almost universal) smoothing of time-based network charges as they currently do for wholesale energy costs. Smoothing variability in network charges would effectively take the form of risk pooling or insurance 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

Box 12.5 **How might retail tariffs reflect cost-reflective network charges**

The price of electricity 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 (including carbon pricing)
- various environmental costs (and in Victoria, smart metering)
- retail costs, including for customer procurement, billing services, financing the necessary working capital, and a profit margin.

The retailer recovers these costs from customers.



Various factors (such as barriers to competition) could mute the incentives for retailers to reflect the time-based differentiation of network charges in final electricity prices. Nonetheless, the Commission is confident that these incentives can be strengthened, so that time-based network charges would translate reasonably directly into the prices faced by many households and businesses. This would be either as retail prices that vary by time or, for those consumers who choose not to adopt time-varying retail prices, as high flat (uncapped) tariffs that reflect the full costs of supplying power to them.

Source: AEMC (2011a, pp. ii-iv).

usually call for some degree of risk-reduction — and a passing-through of price risks to customers to correct for the moral hazard[15] from high peak consumption. In the electricity market, another risk management approach in regard to variations in network charges 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 genuine bill savings through a combination of time-dependent tariffs and demand management services to manage price risks.

The AEMC in its Power of Choice review anticipated that retailers are likely to pass through the structure of network charges in a way that closely resembles their original form (2012u, p. 171). Where the network tariff is flat, it would be teamed with a flat energy usage charge. If a network charge included some time-based components in the tariff, the overall retail charges would likely also incorporate that variation.

Conversely, KPMG (2008) was sceptical about the appetite for retailers to pass through price variability in tariffs. 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 network charge that followed the time of use tariff (applied by Ausgrid as a distributor). However, of those customers with an external retailer, only an estimated half of these faced time of use tariffs from their retailer of choice (EnergyAustralia 2009, p. 9).

The key quandary for network businesses is, in practice, what degree of demand management would be initiated by pricing plans of retailers, since hedging and bill smoothing may distort consumption responses to cost-reflective network charges. 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

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

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 they 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.[16]) 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.

Despite the possibility that some retail products 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 (chapter 11). Further, the prospects of a national wholesale energy hedging market developing (chapter 19) 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 12.6). Chapter 11 also explains why it is unlikely that retailers would attempt to expose household consumers directly to the pricing volatility in the wholesale energy market and why it would not be efficient for them to do so.

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 National Energy Customer Framework (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

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

- 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.

Box 12.6 **A national hedging market would 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 19 suggests two key changes that would help 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 (recommendation 19.2). (The costs and benefits of this option have yet to be formally assessed.)
- 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.).

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, as this would suppress innovation and contestability in the market over the longer term.

12.4 The AEMC's proposed 'demand response mechanism' in the Power of Choice review

Addressing the incentives of network businesses and other NEM participants to adopt demand management was a focus of the AEMC's Power of Choice review. The AEMC gave particular focus to securing demand-side participation from commercial and industrial end-users.

The Commission has sought to avoid duplicating much of Power of Choice review. However, it notes that one of the AEMC's proposals in this review is to allow consumers to be paid the wholesale electricity spot price for reducing their demand (2012u, p. ii, rec. 1). The AEMC considered the proposal would mainly apply to large electricity users, such as commercial and industrial end-users that wish to offer their demand response to the wholesale electricity market directly, or through a specialist intermediary such as a demand aggregator. It envisaged that, in future, the proposal could be adapted by aggregators to include demand responses from residential consumers who have appropriate metering technology in place (2012u, p. 112).

The Commission has not analysed the finer details of this proposal, but observes the following:

- The proposal enhances consumer participation in the wholesale spot market. As the AEMC noted:

  > Our overall assessment of the DRM [demand response measure] is that it meets the NEO [national electricity objective] in a number of ways. Firstly it enhances consumption participation in the wholesale market and allows consumers to see the value of changing their consumption in line with market signals, such as the spot price. In turn, we consider that informed consumer choices leading to efficient consumption in the market will result in lowered generation and network costs, as well as increased competition in the energy market that will benefit all consumers (2012u, pp. 120-1)

- Removing barriers to demand aggregators participating in the spot market could be beneficial. Demand aggregators may be able to source load reduction more cheaply than retailers. Allowing their participation may 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.) Demand aggregators could also provide a link between the underlying market value of distributed generation sources and spot market outcomes.
- The AEMC identify some adverse or perverse outcomes, but did not consider these to be significant. For example, it noted that its proposal could work in opposition to an existing successful demand management response program such as SP AusNet's critical peak pricing program. However, it considered this could be 'easily remedied' by adjusting how the consumer's baseline consumption is estimated (2012u, p. 126). (The baseline consumption together with the consumer's actual consumption is a necessary part of estimating the demand response delivered to the wholesale market.) The AEMC also noted the scope for consumers to 'game' their baseline consumption. However, it considered this depended on the governance arrangements for estimating baseline consumption (pp. 135-6).
- Several participants in this inquiry commented on the AEMC's proposal.

- Some considered its costs outweighed the benefits (Energy Supply Association of Australia, sub. DR70; Energy Retailers Association of Australia, sub. DR76). For example, the Energy Supply Association of Australia considered that: the proposal imposed risks on energy retailers and generators at the expense of rewarding consumers; the link between the proposal and purported network savings were unclear; and establishing baselines was complex and subject to gaming (sub. DR70, pp. 4-5).
- In contrast, EnerNOC (2012, pp. 3, 5; trans., p. 387), a demand aggregator, supported demand-side bidding, considering that the costs should be very small in comparison to the benefits. It suggested improvements to address issues with NEM dispatch and settlement processes that could unlock further benefits.

13 Distributed generation

Key points

- Distributed generation produces power close to the point of consumption. This can 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 (some now scaled back) 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 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 some 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 carbon pricing, such reform would also make redundant an assortment of inefficient distributed generation subsidy arrangements, such as elevated 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 improved signals for investment.
- The immediate prospects for large network savings from the efficient use of distributed generation are low; some networks claim it has led to no deferral of network expenditure to date. It is anticipated that network savings should rise as regulatory obstacles to its uptake (including restrictions on cost-reflective pricing) 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.

In Australia, 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 finding suitable space for generators in major cities. 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 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) although most refer to generation located close to users 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, some DG units 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). Table 13.1 shows the Australian Energy Market Commission's (AEMC) classification of DG units according to their installed capacity.

Table 13.1 AEMC classification of distributed generation units

Classification	*Technical definition*	*Typical installation*
Micro	Less than 2 kW and connected to low voltage network	Rooftop solar PV
Mini	Greater than 2 kW 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

Source: AEMC (2012e, pp. 162-3).

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.

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 detailed 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 in the residential sector (almost entirely rooftop photovoltaics (PV)).

Table 13.2 **DG reported by responding Network Service Providers[a]**
Number of DG projects and capacity, April 2010

Organisation	*Residential*		*Commercial*		*Industrial*		*Other*	
	No.	MW	No.	MW	No.	MW	No.	MW
ActewAGL	3 051	5.9	–	–	–	–	–	6.73
CountryEnergy	16 500	43	–	–	2	60	–	–
Energex	40 224	77	–	–	–	–	–	–
Energy Aust	25 000	45	–	–	–	–	43	268.50
Ergon Energy	–	–	3	3.360	–	–	–	–
Horizon Power	1	1.46	1	0.500	–	–	–	–
Integral Energy	–	–	1	1.300	–	–	–	–
SP AusNet	–	–	–	–	1	–	–	–
Western Power	4	2	1	0.012	–	–	–	–
TOTAL	84 780	174.36	26	37.170	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 were the result of organisations requesting no public disclosure of certain projects.

Source: Ghiotto et al. (2011, p. 18).

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)

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
- electricity at a lower price than that delivered from the grid, particularly in rural and remote locations.

Given the scope of this inquiry, the Commission has focussed only on DG’s effects on network costs. However, in doing so, the Commission has also considered 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 peak demand effects

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 … [DG] … 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)

At the Commission's public hearings following the release of the draft report, Sustainable Rural Australia provided an example of this, referring to the experience of Magnetic Island:

> They had two submarine cables that connected them to the mainland and they were looking at the requirement to upgrade to a third cable, which was a several million-dollar infrastructure upgrade. With the implementation of energy efficiency programs, peak-demand management programs and the use of mainly solar photovoltaics on the island, they have offset or they have avoided the requirement to upgrade to a third cable ... (trans., p. 64)

The Dynamic Avoidable Network Cost Evaluation model[1] illustrates the scope for network savings that DG might provide. Using this model, Langham et al. estimated

[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.

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 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). Box 13.2 provides an example of how network businesses assess such network/non-network alternatives.

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 the summers of 2010-11 and 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 (\$Net Present Value)	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

Energy Australia's analysis concluded:

> The preferred option is a network support agreement with a tri-generation 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.

Source: Ausgrid (2010b).

Networks will tend to 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/year[2] 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).

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 option (with typical costs just over $1.5 million/MW).[4] 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 for reliability standards are also driving projected network investment and augmentation (chapter 15). In this arena, some DG has the potential to meet reliability requirements and so reduce the need for network augmentation. For example, in a report commissioned by the AEMC, Futura Consulting found:

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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’.

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.

4 The Melbourne Energy Institute (sub. DR73, p. 2) noted that advances in technology are improving the cost-effectiveness of solar to provide distributed peak generation capacity, referring to an example of where a 20 MW solar power facility in the ACT is expected to deliver power at around $0.8 million / MW peak.

> 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).

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; Pacific Economics Group, sub. DR48, p. 9).

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.

Modelling by the CSIRO for large DG penetration on four actual distribution feeders in Australia has previously indicated that while these problems exist, they were unlikely to be significant in the period to 2050 (CSIRO 2009, pp. 30-1). That work suggested additional network investment to address these problems was likely to be relatively minor overall, although costs could be concentrated in some areas.

However, the massive (and largely unanticipated) growth in residential PV installations since 2009 is imposing added costs for some networks. For this type of DG, the AEMC has found that issues related to voltage rise and harmonic imbalances are a concern for the network where high concentrations of PV installations occur (Futura 2011, p. 11). Smart Grid Australia noted that the high level of solar PV on parts of the grid is causing issues of network stability and voltage control (trans., p. 252), while Ergon Energy noted:

> Networks have not been designed to handle large export power flows at the distribution level … In Ergon Energy's experience, high penetration levels of distributed generation have resulted in additional network augmentation costs. (sub. DR63, p. 8)

The Energy Networks Association has noted that these 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.[5] (ETSA Utilities 2010b, pp. 4-5)

Further, the adoption of smart grid technologies (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; Pacific Economics Group, sub. DR48, pp. 7-8).

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).

5 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-based DG from rooftop PV panels.

13.5 Obstacles to efficient network investment

Ideally, when network businesses consider how best to meet future demand, they should be neutral between network and non-network solutions to deliver the most efficient outcome. Unfortunately, this is not always the case.

Despite recent reforms aimed at facilitating the efficient network use of DG,[6] participants highlighted areas that remain of concern and where further changes are needed.

Participants' concerns

Some participants 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. (Clean Energy Council, sub. 31, p. 2)
>
> However, networks have financial incentives to forgo DG investments whenever they reduce the network's overall regulated asset base or reduce … energy sales. … Cost-based, building block regulation creates inherent incentives for networks to forgo DG investments when these investments are more economical than network expansions' (Pacific Economics Group, sub. DR48, pp. 10-11)

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:

6 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).

> 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)

Similarly, SKM noted that although customers are becoming more active in self-generation, they are not well informed about network costs and capability. This, it argued, leads to a situation where 'integrated planning between customers and networks around embedded resources is inefficient' (sub. DR61, p. 2).

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 recent 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 networks operating under weighted average price caps (as opposed to revenue caps) set by the regulator are still exposed to a disincentive to use DG as an alternative to network augmentation, despite efforts to counteract this effect (chapter 12 addresses this issue in depth):

> When it comes to the use of demand-side alternatives, NSPs' incentives are also muddied 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. …
>
> 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. (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 distorts 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. (Chapters 10 and 12 discusses this issue further.)

The City of Sydney (sub. DR58, p. 8) and Origin (sub. DR64, p. 5) argued that disproportionately high network tariffs applied to exports of DG power into local distribution networks, and that these constitute a major barrier to precinct scale DG:[7]

> The economies of scale of having a larger sized generator that has spare capacity to supply thermal energy to other buildings in the vicinity is largely hindered if other off-site clients have to pay full network charges. (Origin, sub. DR64, p. 5)

The City of Sydney noted that overseas this problem has been resolved by treating the local public wires of the distribution network as if they were private wires, and paying the distribution network operator 'use of service charges'. For these charges:

> … there was a standardised calculation method, … which sets out what the charge should be for distance travelled, the amount of energy being exported et cetera … there's a very detailed formula that you could literally take off the peg and apply that to Australia. (trans., p. 103).

This solution appears predicated on the principle that users of electricity should only incur a network charge in proportion to that part of the network used by the electrons they consume. However, identifying the source of any electrons used by consumers and identifying that part of the network used in getting those electrons from generation to final consumption, is impossible. Moreover, paying a theoretical marginal cost or 'use of service charges' for transporting DG-produced power to nearby users ignores the cost of providing a network that can deliver power should that DG-produced power fail. These considerations underpin the existing postage stamp basis for network charges.

Jemena noted that a network business is exposed to 's-factor' penalties if a DG provider that it relies on for network support fails to perform and, as a result, contributes to an event that causes the DNSP to incur a penalty. In Jemena's experience, DG providers are generally unwilling to indemnify DNSPs against this exposure. This, it notes, has been a barrier to the development of network support arrangements with DG providers (sub. DR77, pp. 18-9).

[7] It is worth noting that Clause 6.1.4 of the Rules aims to ensure distribution-connected generation is treated equally to transmission-connected generation by prohibiting the application of charges for energy exported to the distribution network.

However, this situation appears to describe the freedom of DG providers to make commercial decisions on whether to enter into agreements to indemnify the DNSP, rather than any ‘barrier’ to DG providing network support.

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 et al., 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 2012, p. 55)

Recent and imminent reforms address many of these concerns, but some remain

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 reforms.

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 recently considered 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 final determination on this rule change request in October 2012 (AEMC 2012c). The VCEC has observed that this rule change would 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 et al., 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, including:

- new connection charge guidelines under chapter 5A of the National Electricity Rules (AER 2012v)
- proposals for rule changes under the Small Generator Aggregator Framework which seeks to simplify the registration of small generator projects[8] (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 South Australia on 1 February 2013 (and in New South Wales and Victoria as soon as practicable) — is intended to address regulatory constraints facing small to medium-scale DG in selling power surplus to their needs in the retail market (VCEC 2012, p. 159).

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 either 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:

8 '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 2009a, p. II).

> … 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 some 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 implemented a Demand Management Incentive Scheme[9] to address systemic bias against non-network alternatives. In New South Wales, for example, the scheme consists of two parts. One part is a demand management innovation allowance (that provides a payment for demand management related activities), and the other is a 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 price caps acting as a disincentive to using DG identified by EnerNOC (sub. 7, p. 2) is yet to be resolved.

Options to address these failings were the subject of the AEMC's Power of Choice review, which released its final report in November 2012 (AEMC 2012u).

Lack of cost-reflective pricing

The lack of cost-reflective pricing referred to by esaa (sub. 23) and IPRA (sub. 36) is a fundamental obstacle to the efficient level of network adoption of DG. As Origin Energy noted:

9 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.

> The introduction of more cost reflective network pricing [would] make a material improvement to the business case for individual building and precinct cogenerated electricity. (sub. DR64, p. 5)

This issue though is particularly applicable to households and small businesses:

> [For] large consumers, … 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. …
>
> 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, pp. 57-60)

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 (sub. 25, p. 3) 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.

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 (and generally inefficient) 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.[10]

The Commission has previously argued that rooftop PV units, supported by these schemes, have also been a relatively high cost option for reducing greenhouse gas emissions (PC 2011d, 2011e). The latter PC report estimated that the implicit abatement subsidies from these schemes for small-scale PV were in the range of \$177–497/t CO_2 (PC 2011e, p. 15). However, as some participants noted, for *future* small-scale PV these costs would be significantly less as premium feed-in tariffs are progressively removed (TEC, sub. DR50, p. 6). The Commission's latest estimates confirm this view. Taking into account current (January 2013) policy settings for feed-in tariffs and subsidies under the Renewable Energy Target scheme, the implicit abatement subsidies from these schemes for *new* small scale PV are likely to be in the range of \$22–252 per tonne of CO2. The wide range arises because some jurisdictions have abolished or reduced their premium feed-in tariffs (that subsidy is now zero) whereas other jurisdictions still have relatively generous feed-in tariffs (South Australia, Tasmania, the ACT and the Northern Territory).

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:

> In our view, the introduction of the carbon price and a move towards an emission trading scheme … removes the need for the RET [Renewable Energy Target] (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)

More importantly, even allowing for the falling cost of solar technology, rooftop PV units are an expensive way of delivering peak power (section 13.4) and these schemes penalise those in the community without solar PV systems with materially higher electricity costs. The latter occurs because energy retailers recover the cost of these schemes through higher power bills. In the case of the Renewable Energy Target scheme, for example:

> 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

[10] The Small-scale Technology Certificates solar multiplier offered under the RET scheme was reduced from two to one on 1 January 2013 (Combet 2012). The Climate Change Authority conducted a review of the RET scheme in 2012 and released its final report in December 2012. That report recommended that the Small Scale Renewable Energy Scheme continue and its broad structure remain largely unchanged (Climate Change Authority 2012, p. vii).

electricity customer's bill in NSW. This is significantly higher than was forecast when the RET scheme was amended in 2009 and 2010 … (IPART 2012c, p. 1)

Accordingly, the Commission considers that the current subsidies and the RET are inappropriate and governments should phase them out as soon as practicable. In practice, this would be likely to involve grandfathering existing subsidies and phasing in new arrangements to lessen industry disruption and consumer concerns.

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 committed to a new net feed-in tariff to replace existing tariffs for rooftop solar PV, effective from 1 January 2013. This 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 actual 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.[11]

The VCEC also suggested that feed-in tariff schemes continue for existing customers of those schemes until 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 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 chapter 11 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 wholesale 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 (esaa, sub. DR70, p. 5) — although the AER's price reset process might be a vehicle to identify and permit such payments (VCEC 2012, pp. 85-6).

In addition, EnergyAustralia observed that direct payment by distribution businesses to small-scale distributed generators is likely to be administratively inefficient and to undermine the relationship between the retailer and its customer. It suggested a preferable alternative might be for distribution businesses to publish tariffs and/or incentives for different DG types and areas, which retailers could then incorporate in product offerings to customers (sub. DR82, p. 6).

Similarly, while administrative complexity might rule out direct payments to small-scale generators, this should not preclude an intermediary from making a business case for aggregating the contribution of small-scale distributed generators and seeking remuneration on their behalf.

11 In Victoria, the Essential Services Commission's Electricity Guideline No 15 already provides for this to occur (Jemena, sub. DR77, p. 18).

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 by:

- ***instituting arrangements for network businesses to remunerate such generators at a level that reflects the savings in network costs from distributed generation capacity and output, particularly taking into account the extent to which distributed generation reduces the requirements for peak network capacity***
- ***setting feed-in tariffs that approximate the wholesale price of electricity at times of peak and non-peak demand.***

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. (EnerNOC, 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 subsiding 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.

Benchmarking as a diagnostic tool

While benchmarking levels of DG should not be used as a measure of network efficiency, it may be useful in identifying broad trends between networks. For example, if one network used significantly less DG than similar networks, it would be worth investigating why this was the case. This investigation may find evidence on whether DG is being inefficiently ignored, a finding that could then be incorporated in revenue determinations.

This type of comparison may become more important if, over time, new generation and smart grid technologies lead to an increased uptake in DG.

14 Building a reliability framework in order to benchmark

Key points

- Reliable power services are essential for households and industry. Even short and infrequent outages can have significant economic and social costs.
- Standard forms of incentive regulation reward efficient network businesses with greater profits — mimicking the working of competitive markets. However, given that network quality is not always easily identifiable, this can also create incentives for businesses to lower costs by reducing reliability.
- To counter these tendencies, 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 that do not reflect this balance — whether set too high or too low — can be economically costly, even if the standard is delivered 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 consumers (chapters 15 and 16).
- Setting efficient standards requires accurate measures of the value that customers place on reliability. Current estimates of the value 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 (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 short, or occasional long, 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:** describes the likelihood that customers experience power interruptions based on 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 distribution and transmission 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 to identify what constitutes an efficient level of network reliability. This framework is then used in the two following chapters to assess the effectiveness and efficiency of the reliability arrangements currently applying to distribution and transmission networks and how they might be improved.

14.1 What issues does reliability raise?

More than 60 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. 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 standards have been one of the major sources of network price increases in recent years (for example Essential Energy, sub. 30, p. 5 and Ergon Energy, sub. 8, p. 11). The costs of meeting these standards, and thus the resulting price increases have been compounded by the combination of changes in reliability standards and increases in peak demand. 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 (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.[1] 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. Reliability standards would then be freed from the political pendulum of expressions of concern about the costs of reliability and the aversion to particular instances of poor reliability (such as widespread and extended, but rare, blackouts).

The influence of reliability settings on the operation, planning and regulation of electricity networks is well recognised. This 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 network reliability in New South Wales (AEMC 2012l)
- the AEMC review of distribution reliability outcomes and standards at the national level (AEMC 2012k and 2012v)
- the AEMC Transmission Frameworks Review (AEMC 2011f and 2012j)
- the AEMC Transmission Reliability Standards Review (AEMC 2010a)
- the AEMC Review of National Frameworks for Electricity Distribution Network Planning and Expansion (2009b)
- the Standing Council on Electricity and Resources directed AEMC review of National Electricity Network Reliability Framework and Methodology (SCER 2013b).

These reviews examine some of the major questions about reliability in the NEM, such as whether:

- 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

1 Several inquiry participants (ETSA Utilities et al. (sub. 6, pp. 43-4), Ergon Energy (sub. 8, p. 10-11) and the Energy Networks Association (sub. 17, p. 30)) emphasised the important effects of reliability standards on costs, and the obstacles to effective benchmarking posed by different 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
- 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.

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 tradeoff
- 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

Both the revenue and weighted average price caps employed in economic incentive regulation 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 (chapter 5).

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 usual commercial pressures to meet consumers' preferences for the tradeoff 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, imposing greater costs on customers than would have been incurred had the maintenance been undertaken in the first instance. Overseas experiences (box 16.1 in chapter 16) 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. (Similar concerns apply to some aspects of safety — such as the risks associated with fires triggered by network failures — chapters 5 and 7.)

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. Consumers would eventually alter their demand in response to falling levels of reliability and instead seek to ensure reliable supply through using different energy sources (such as gas for cooking or the purchase of generators). There is also a range of regulatory instruments that can encourage higher reliability, involving different degrees of balance between prescription on how to achieve reliability outcomes and penalties for failing to meet reliability outcomes.

Given the above, various standards governing the planning, operation and performance of networks complement incentive regulations in the NEM (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 differ from one jurisdiction to the next and, in the case of distribution, 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 tradeoffs 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. Single lines are effectively available 99.98 per cent of the time (AEMO 2010d, p. 14). This implies that there must be backup (redundancy) for only around one hour and 45 minutes a year.

- 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, lower ratings reduce the likelihood of faults from overheating on lines, and thereby increase reliability. However, 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.
- Networks can take actions to increase reliability after a fault has occurred, 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 aim 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 become smaller (that is, reliability should improve) 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, such as maintaining easements and clearing vegetation from under overhead lines.

2 Line ratings limit the proportion of the maximum capacity of a line that can be used to dispatch electricity throughout the network. Line ratings can be static, meaning that they are constant under different conditions, or dynamic, meaning that the line rating changes in response to different conditions, such as the temperature or the level of wind. The use of dynamic line ratings is discussed in chapter 16.

More generally, the higher the level of reliability, typically the more costly it is 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 accidently 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 (Jamasb et al. 2010).

While network operators will have a detailed knowledge of the costs and means to increase reliability, governments, regulators and in particular the community, 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 judgments 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 16).)

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 need to take account of the divergences in reliability standards that apply across the NEM. Even so, given the large potential benefits from even modest efficiency gains in meeting expensive reliability standards, 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 that consistency in the expression of standards might facilitate benchmarking, the critical issue is the optimality of the standards themselves. The costs of an increase in reliability will ultimately be included in customers' bills, while the costs of low reliability will also be borne by customers suffering interrupted electricity supply. Accordingly, regulators should carefully consider the incentives that network businesses have to meet standards efficiently, as well as the settings of the standards themselves.

14.4 What level of reliability is efficient?

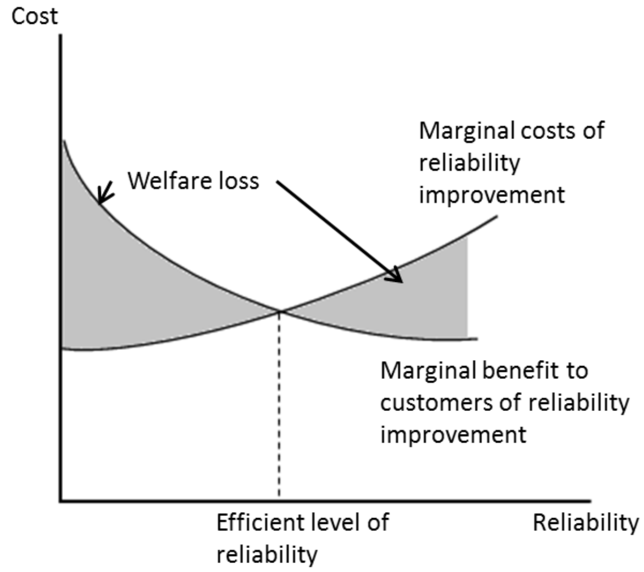
Just as customers value the quality of physical products differently, so too will they place different values on reliable electricity supply. In competitive markets, the determination of the efficient level of quality is often solely left to the interactions between many suppliers and many consumers. 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 14.2). 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.

Box 14.2 **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: Ajodhia and Hakvoort (2005); Jamasb et al. (2010).

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 tradeoffs between reliability and costs, regulators must use indirect methods to set an efficient standard.

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 are unlikely to 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.

Customer Damage Functions (CDF) capture such changing cost patterns by 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 14.3). By way of

3 Unserved energy is the amount of electricity demanded by customers that is not delivered due to interruptions over a given period.

illustration, sector CDFs suggest that customers in agricultural industries experience costs of around two dollars per kilowatt for an interruption lasting one minute.

Box 14.3 **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.

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).

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**

Year	*NSW*	*Vic*	*Qld*	*SA*	*Tas*
	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
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 table 14.1 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 they considered that service was 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 (2012b) 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 costs for these two jurisdictions.

The differences may reflect methodological variations, different customer categories (and the associated sample weights), 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]**

	Vic VCR (AEMO)	*Sector*	*NSW VCR (AEMC)*
	$Aus/kWh		$Aus/kWh
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 14.1 because it has been indexed to 2012.

Source: AEMC (2012i, p. 42).

Estimated VCRs in Australia are generally high by international standards (table 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.

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 2012i, 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).

Table 14.3 International measures of value of customer reliability for comparison

Region	*Sectors*	*Origin value*	*Year*	*$Aus (2009)/kWh*[a]
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

[a] Values are converted to Australian dollars using at the market exchange rate at the time and may mean the comparison values are subject to additional error due to divergence between the exchange rate and country level purchasing power.

Sources: Hickling (2010, p. 11); New Zealand Electricity Industry Participation Code (2010, Schedule 12.2, p. 92).

Table 14.4 Estimated values of customer reliability in the US by customer type and duration (for a summer weekday afternoon)[a]

Interruption Cost	*Interruption Duration*				
	Momentary	*30 minutes*	*1 hour*	*4 hours*	*8 hours*
	$US	$US	$US	$US	$US
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	2 401	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).

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 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 issue, 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 from a line serving an area that is largely agricultural. AEMO uses the same weighted customer costs in areas with different customer profiles.

There are also issues with the methodologies that underlie the various measures 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 occur 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 increased awareness and better information about the electricity product being consumed should improve the accuracy of the results.

Contingent valuation studies, including studies of electricity reliability, have also found a preference for the status quo (Hartman and Doane 1986; Hausman 1979). 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 EnergyAustralia

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.

(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 have questioned whether attempting to compute customer reliability values is worth the effort (for example, the National Generators Forum, sub. DR93, p. 17).

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 (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. Otherwise, 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) — a view supported by some stakeholders (including, for example, AEMO (sub. DR100, p. 4) and the Energy Networks Association (sub. DR71, attachment A, p. 14).

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. AEMO considered that such refinements to the approach would be beneficial, stating:

> AEMO's National VCR project will be an enhancement to the approach undertaken previously in 2007 by taking into account the shortfalls identified by the Productivity Commission above.
>
> To develop a set of National VCR numbers which is reflective of current economic conditions and consumer perceptions of reliability, AEMO will fully review the recommendations from the draft report on the approach to valuing customer reliability as well as the recommendations of previous VCR work. (sub. DR100, p. 4)

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 widespread 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. Costs might include trucking in fuel for generators and fresh water from long distances, and 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. 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 dwellings that are next door to each other. Accordingly, efficient levels of reliability do not mean that every person or business will get their desired tradeoff 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 are unable to receive less reliable services at lower costs.

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. 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 households (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, they may be provided with a subsidy. Any such subsidies should be transparent, and funded efficiently (chapter 11). (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 customers on lower incomes 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. A VCR framework would be likely to deliver significantly less reliability in more remote areas.

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. Subsidies provided by governments are more generally termed Community Service Obligations and represent purchases on behalf of certain groups by governments. Regardless, any 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 matter 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 are likely to increase over time with developments in distributed generation. 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 tradeoff 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 distribution and transmission networks, and the regulation affecting reliability in each.

RECOMMENDATION 14.1

Reliability standards throughout the National Electricity Market should be based on the value that customers place on network reliability.

RECOMMENDATION 14.2

The Australian Energy Market Operator (AEMO) 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.

AEMO 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. AEMO should use these measures to supplement the results of the surveys.

15 Distribution reliability

Key points

- Reliability in distribution is usually measured by the frequency and duration of power interruptions in the network.
- Most power interruptions that customers experience reflect faults or failures in distribution networks.
- Distribution reliability varies significantly between jurisdictions and network 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, such as:
  - 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.

15.1 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 or extreme weather. Wind, lightning, birds, possums, cars and trees, for example, can affect overhead lines. Density of customers in different areas also affects reliability, with rural areas more likely, on average, to experience longer interruptions due to slowly repair response times by businesses given they have a greater geographic coverage (per customer).

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. 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 are 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 15.1). 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 15.1 **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 indices 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.

15.2 Reliability performance of distribution businesses in the National Electricity Market

Over the last 10 years, state and territory average 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, and 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)

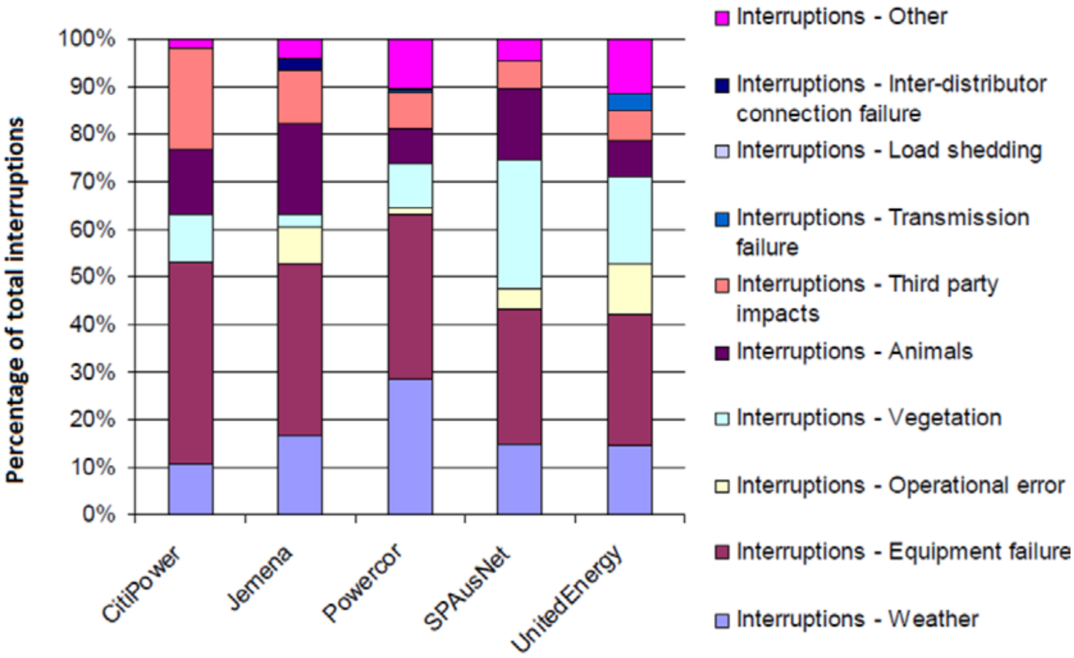
Some factors affecting reliability, such as the condition of the network and the level of redundancy (subject to planning and reliability standards), are controlled by the business. Others, such as severe weather events and customer density, are not. For example, some networks — and especially those 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 15.1). 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 15.1 **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 more 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 reliability outcomes by meeting customer preferences, given the characteristics of the network. It will do so for a low cost and by 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, efficient reliability levels for distribution networks have two dimensions.

- 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 tradeoff 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).

15.3 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 specific planning and performance requirements to complement incentive regulation in the NEM (box 15.2). (Governments also apply safety standards to distribution businesses, some of which operate under approaches consistent with incentive regulation (chapter 5), others under prescriptive regulatory approaches — chapter 7.) The frameworks in which these standards are applied to distribution businesses differ between jurisdictions (table 15.1).

Box 15.2 Reliability specific planning and performance requirements

Throughout this chapter, the reliability settings imposed on distribution businesses are termed reliability specific planning and performance requirements. These comprise:

- standards — generally these are planning requirements placed on businesses that require a certain level of redundancy in specific parts of the network. These are usually expressed as 'N-x' requirements (appendix F)
- probabilistic planning requirements — represent a 'performance standard' or criterion imposed on the distribution businesses, such as a requirement that reliability improving investments take place if the benefits from doing so exceed the costs
- targets — represent maximum outage levels that a distribution business should seek not to exceed
- guaranteed service levels — minimum levels of service requirements that should be provided to individual customers within a distribution network.

Distribution businesses in the NEM are required to plan and build their networks to meet the security requirements to ensure stability of the network (these are contained in schedules 5.1a and 5.1 of the National Electricity Rules, hereafter the

‘Rules’). Apart from this requirement, ‘service reliability standards’ are state and territory functions (SCER 2011b, annexure 2, p. 2).

Table 15.1 Jurisdictional reliability planning and performance requirements

Jurisdiction	*Planning criteria*	*Performance measures*[a]	*Performance measures applied to*	*STPIS - current or due to commence*	*Jurisdictional performance measures consistent with or additional to STPIS*
NSW	Deterministic, set out in licence conditions	SAIDI, SAIFI are expressed as standards and 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 distribution businesses in line with STPIS targets set by AER	Feeder type	Currently in operation	Consistent
Qld	Deterministic, set by distribution businesses in network management plans	SAIDI, SAIFI set out in Code[b]	Feeder type	Currently in operation	Additional
SA	Deterministic, set by distribution businesses	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).

Reliability specific planning and performance requirements 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 targets, 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' (guaranteed service level) requirements protecting customers who experience significantly poorer reliability outcomes than the average. In some jurisdictions, distribution businesses are required to make guaranteed service level payments to compensate customers when reliability standards are not met (such as in Victoria).

The types of reliability planning and performance requirements imposed varies significantly between jurisdictions, but also between businesses within a jurisdiction. This variation can affect how easy it is to benchmark distribution businesses as different reliability planning and performance requirements can have a large effect on the costs of a business.

Inefficiencies in the type, level, and combination of reliability planning and performance requirements applied to each distribution business can lead to inefficient reliability investments across distribution networks. For example, deterministic 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 also limited controls placed on distribution businesses to ensure reliability investments are efficient. While reliability investments by distribution businesses are now subject to some scrutiny through the Regulatory Investment Test for Distribution, a preferred option identified in the Test may have a net economic cost (fail a cost–benefit test) if the investment is required to meet a reliability standard (Rules s. 5.17.1(c)(9)(v)). The Commission has recommended that this feature of the Regulatory Investment Test for Distribution be removed — chapter 10.

There are three main dimensions of cost and inefficiency in reliability planning and performance requirements 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. Hence, duplicative, overlapping or different reporting requirements inflate compliance costs to businesses. These costs increase further if applicable sets of planning and performance requirements 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 on costs to customers of different reliability planning and performance requirements applied in the NEM, keeping in mind the role that such requirements play under incentive regulation — an exercise of regulatory benchmarking. An assessment is also made of how current reliability planning and performance requirements 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 business's licence conditions (a description of deterministic standards in the context of transmission networks is contained in appendix F). The New South Wales Minster for Energy introduced the standards in 2005. Before then, businesses were responsible for determining the appropriate level of reliability (AEMC 2012i). These deterministic planning standards that have required higher levels of redundancy 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, p. 157 and Rollinson 2013, p. 23).

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 the Essential Services Commission of South Australia 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]

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.

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 they deliver reliability with consideration of high cost, low probability events. Mostly, distribution businesses in Victoria conduct their own probabilistic planning when making their planning decisions (the probabilistic process they use is similar to that used by the Australian Energy Market Operator (AEMO) for transmission in Victoria and is described in appendix F).

Consequences for efficiency

There are also costs in setting prescriptive regulations that specify how a distribution business should plan its network to meet reliability standards. The additional costs arise because, for a given level of reliability, the lowest cost combination of inputs (redundancy, maintenance, operational flexibility, portable energy generators 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 [operating expenditure] and Capex [capital expenditure] … 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 a given level of 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 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 standards of the form N-1 (see appendix F).[4] These standards, however, have imposed high costs on Energex and Ergon Energy customers and it is not clear that the resulting increased levels of reliability are adequately valued by them. 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 and IRPNC 2012, p. 13).

4 For example, the report recommended, ‘that for assets as important as bulk supply sub-stations, “N-1” should be the standard used’ (2004, p. 15).

Customers would only be willing to pay for augmentations to a distribution network to meet deterministic standards if they value the increases in 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. Consequently, it is likely that the level of reliability set by the deterministic standards is inefficient.

While this type of inefficiency is less likely to exist for distribution businesses that use probabilistic planning (as this uses a cost–benefit framework informed by the customer values of reliability), there are costs attached to undertaking a full probabilistic assessment every time a constraint emerges on a distribution network.

Jurisdiction-specific performance targets

Distribution businesses are required to meet performance targets 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 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 reliability targets. (The exception is incentive-based safety targets, in particular, the 'F-Factor' scheme introduced in the wake of the 2009 bushfires with the aim of reducing the number of fires started by electricity assets (box 15.3).) Whether the jurisdictional targets 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 targets are set most commonly using SAIDI and SAIFI performance indicators (for example, table 15.2) although in some jurisdictions, there are also targets for MAIFI and CAIDI. In most jurisdictions, performance targets are determined according to feeder type — whether they are CBD, urban, or short or long rural feeders.[5] Categorising performance targets by feeder type recognises that those feeders that are longer, have less redundancy and are further away from maintenance crews, generally have lower reliability and that these feeders generally service areas with lower customer density. South Australia, however, does not use

5 Feeders represent the lines that emanate from a substation.

feeder types, but rather sets targets 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.

Box 15.3 **The F-Factor scheme**

In response to the 2009 Victorian bushfires, the Victorian Department of Primary Industries introduced a financial incentive scheme to encourage the management of electricity distribution assets with the aim of reducing the number of fires started by those assets. The scheme became operational in January 2012.

The scheme was specifically designed to operate in a similar way to the STPIS. It recognises that while the five year expenditure allowances include an allowance for bushfire mitigation, actual mitigation activities delivered by distribution businesses may be below levels for which customers are willing to pay as there are not strong market signals to encourage efficient mitigation levels. Therefore, bushfire mitigation activities may be inefficiently low. Incentive payments (and penalties) are used to encourage distribution businesses to increase mitigation activities to efficient levels.

The scheme was specifically designed to complement the STPIS regime, meaning any costs related to inconsistencies between it and the STPIS are likely to be minimised — unlike the additional reliability standards imposed by other jurisdictions in the NEM.

Source: DPI (2013a).

Sometimes, as is the case in Tasmania and South Australia, the target levels 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 targets.

Jurisdiction-specific performance targets are set by the state regulator in South Australia, Tasmania and the ACT.[6] 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 targets.

Businesses in Queensland, South Australia, Tasmania, and Victoria are required to use ‘best’ or ‘reasonable’ endeavours to meet targets. ActewAGL faces penalties for

6 In the ACT, these are minimum performance targets and the business can set higher targets.

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 their reliability targets and can range from fines of around $100 000 to revocation of a business's licence (although this has never occurred in the NEM).

Table 15.2 **Queensland distribution network performance targets, 2010-11**

Distribution business	*Feeder type*	*SAIDI (minutes) per year*	*SAIFI per year*
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).

Distribution businesses are required to report their performance against their targets, with (potentially) additional reporting in the event of a failure to reach their targets. For example, in New South Wales, distribution businesses are required to report their performance against the targets to the Minister quarterly and include reasons for failing to reach their target. Distribution businesses in New South Wales are also required to provide an independently audited report annually to the Independent Pricing and Regulatory Tribunal (AEMC 2011g, p. 18).

Consequences for efficiency

The discussion above highlights that no two jurisdiction-specific reliability performance frameworks are the same. The Australian Energy Market Commission (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. (p. xii)

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 may need to be controlled for in benchmarking.

Benchmarking the targets 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 targets in addition to the STPIS are not immediately obvious. However, it is possible that jurisdictional authorities value retaining an ability to remove the licence of a grossly underperforming distribution business. However, this power aside, it is not clear why jurisdictions do not align their targets with those in the STPIS, as is the case in Victoria. Requiring distribution businesses to adhere to and report their performance against two sets of targets (and could be viewed as three when reporting against planning standards is considered) is costly to consumers and does not seem to produce obvious benefits. According to Endeavour Energy (2012a):

> 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 of jurisdictional control of targets is that customers may feel that a local target-setting body would take account of their preferences and be more responsive to local needs. However, no jurisdiction-specific targets incorporate customer values in setting targets (as distinct from the AER's STPIS and Victoria's probabilistic planning requirements). Rather, significant changes to targets by jurisdictional authorities appear to occur in response to political pressure or intervention and publicly-expressed customer discontent, which are, at best, delayed and reactive responses to customer demands, and take no account of the costs of meeting the targets. These 'reactive' responses could also be disproportionate to the actual overall value the customers place on rectifying the issues in question, and may not be targeted appropriately in any case.

Using the historical performance of a business to set targets can also be inefficient since the resultant targets — and the costs of meeting them — may be divorced from the customers' values of reliability (chapter 14).

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. However, at the time the STPIS was introduced into Victoria in 2011 it was anticipated that the guaranteed service levels component would commence at the beginning of the next regulatory period (AER 2009d, p. 99).

Reliability of supply

The STPIS sets performance targets according to feeder type for distribution businesses using unplanned SAIDI, unplanned SAIFI, and MAIFI indicators.[7]

The AER sets performance targets for these indicators at the beginning of each regulatory control period during the revenue determination process (table 15.3). 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 15.4)
- any improvements in reliability that are anticipated to result from expenditure that the AER has or will approve in past or current revenue determinations.

7 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.

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.

Table 15.3 **Example targets for STPIS reliability of supply component and corresponding state-based targets**

Parameter	*Unit*	*Ergon Energy's Targets*				
		2010-11	2011-12	2012-13	2013-14	2014-15
STPIS targets						
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
State targets (minimum service standards)						
SAIDI	Minutes					
Urban		149	148	147	146	145
Short rural		424	418	412	406	400
Long rural		964	948	932	916	900
SAIFI	Interruptions					
Urban		1.98	1.96	1.94	1.92	1.90
Short rural		3.95	3.90	3.85	3.80	3.75
Long rural		7.40	7.30	7.20	7.10	7.00

Sources: AER (2009c, p. 304); QCA (2009, p. 20).

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 such events. 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 accidents, such as positioning poles further from roads (albeit at a cost) (AEMC 2012k, p. 32).

Box 15.4 **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 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 (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).

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 their control. For example, there have been suggestions that raising the threshold would be more appropriate (from the current minimum 2.5 standard deviations to 3.5 standard deviations). 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).

These matters illustrate a problem common with many incentive schemes — that they can potentially 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 the accuracy of the value of customer reliability (VCR) used to determine incentive payments in the STPIS, customers may also have not been adequately consulted for some of the other components and targets. For example, do customers care much about the exact reasons for an outage? It is likely that many customers only care about having their power supply restored quickly, rather than whether the outage was planned, unplanned or due to an event defined as 'controllable or uncontrollable'. It is important 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.

Quality of supply component

While the STPIS allows for the quality of supply to be measured (for example, the absence of voltage spikes), no targets are currently specified for distribution businesses to meet.

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 (or 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 15.4, 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.[8] This is not the case in some of the guaranteed-service level schemes applying at the jurisdictional level, where customers must request payments.

[8] Distribution businesses do not have to make payments when they are not responsible for missing a target (for example, due to transmission failure).

The guaranteed service levels component of the STPIS is not currently applied in any jurisdiction in the NEM (although it was anticipated to begin in the next regulatory control period for Victoria (AER 2009g, p. 99)). Instead, jurisdiction-specific schemes containing a wide range of parameters, targets and levels of payments are applied.

Table 15.4 **Guaranteed service level parameters, thresholds and payments in STPIS**

Parameter	*Threshold*[a]	*Penalty per occurrence above the threshold ($)*
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

[a] Thresholds are per regulatory control period where applicable.

Source: AER (2009h, 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 with a request for information 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.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 was inherited by the AER in the transition of responsibilities from the Essential Services Commission of Victoria and now forms 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 (noting some issue surrounding the accuracy of the VCR estimates — chapter 14) 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 2009h, p. 10). In this way, the incentives for businesses to meet their targets are related to an assessment of the costs (benefits) that customers experience when businesses fall short of (exceed) their targets.[9]

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 (which primarily services rural and remote customers) to 7 per cent for SP AusNet in Victoria (which primarily services urban customers). 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 receives additional revenue because the AER allows it to increase its prices to customers — they effectively pay

9 These values are taken from estimates of Victorian VCRs and so do not accurately reflect the true VCR for most distribution businesses. In line with recommendation 14.2, the AER should replace these with actual VCR estimates by feeder type for individual distribution businesses (section 15.4).

an additional price for the improved quality of the service they receive. Likewise, if a network business fails to meet its targets it is penalised and has to reduce its prices to customers, who receive some compensation for the poorer performance. The fact that customers ultimately pay for the performance encouraged by the STPIS emphasises the importance of aligning the STPIS targets with customers' value of reliability. Further, the two-sided nature of payments (penalties and rewards) avoids a 'cliff edge' effect. The Brattle Group (2012a) contended that without this feature:

> … 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. (pp. 14-5)

Consequences for efficiency

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, there is room for significant strengthening and streamlining of reporting requirements in the STPIS, especially outside Victoria. Furthermore, the Commission considers all non-commercially confidential information should be released publicly. Where confidentiality concerns exist, the onus of proof should lie with the business to show why any of this information is commercially confidential. After all these are regulated monopolies.

The STPIS currently operates alongside existing jurisdiction-specific reliability planning and performance requirements, and therefore, not every business is subject to the same parameters of the scheme. This inconsistency adds to the factors that any benchmarking exercises must consider — and therefore the complexity and difficulty of such exercises.

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.

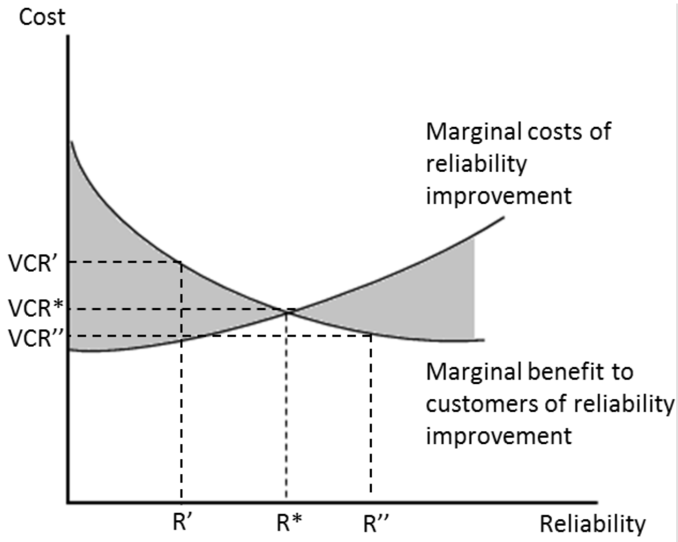
- The targets are based on the historical performance of the business. As discussed in the context of jurisdiction-specific targets, as a basis for a reliability target, historical performance does not have regard to customers' willingness to pay.
- The rewards and penalties received under the scheme are unlikely to be providing the right incentives to distribution businesses to encourage them to meet customer preferences efficiently, due to problems in using a single VCR (box 15.5) and the implications of errors (box 15.6). A single VCR applied to all distribution businesses ignores the likely differences in customer preferences between distribution networks, and indeed those of customers within individual distribution networks.

Box 15.5 **The problem with incentive payments based on a constant VCR during a regulatory period**

As discussed in chapter 14, the efficient level of reliability occurs 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 at differing levels of reliability, 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.

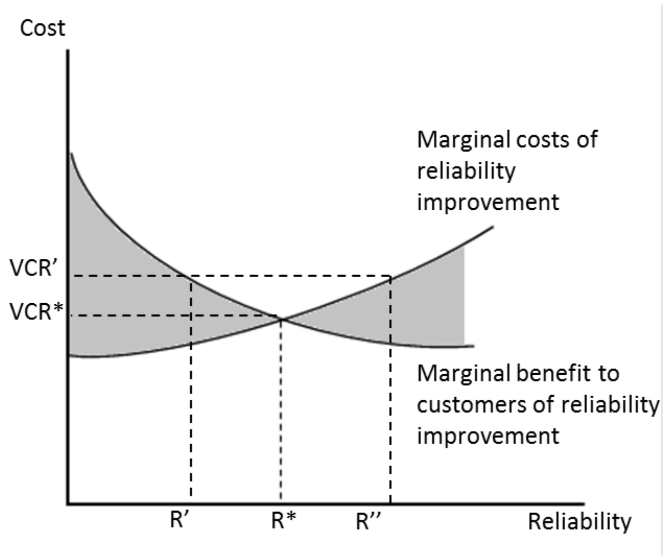
In reality, however, applying variable VCRs that correspond to a marginal benefits curve like that in the figure is challenging, especially considering the difficulties associated with identifying accurate VCRs as discussed in chapter 14. Despite this, given greater challenges and costs in adopting other approaches, such as attempting to set optimal targets which also requires the regulator to accurately determine the marginal cost curve of reliability improvements (discussed below), use of a single but regularly updated VCR for incentives payments is likely to generate efficient outcomes in the longer-term.

Box 15.6 **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.

- 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 the right incentive for businesses to adjust their reliability performance sufficiently. On the other hand, uncapped revenue at risk also exposes consumers to the risk of excessive price fluctuations from year to year, although the s-bank[10] mechanism in the STPIS helps to smooth volatility in prices over time (AER 2009d, p. 10).

15.4 An efficient and effective distribution reliability framework — a bolstered STPIS

Remedying the above limitations would improve the efficiency of reliability planning and performance requirements and the frameworks in which they operate. It could also improve managerial performance if it improved the prospect for more accurate benchmarking of the kind described in chapter 8.

Removing input standards

An efficient reliability framework would 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 efficient 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.[11] 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)

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10 The s-bank mechanism allows a revenue increment or decrement (or portion thereof) to be delayed by one regulatory year for the purpose of reducing price variations to customers.

11 While this arm’s length approach is appropriate for distribution businesses, which can be encouraged to deliver reliability using incentive regulation, it is not appropriate for transmission networks, where transmission-specific characteristics (chapter 16) require a more ‘hands on’ approach to NEM-wide transmission planning.

Energex (2012) agreed:

> … planning standards (e.g. utilisation) 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 could be substantial. As an example, AEMO calculated the cost savings of removing the deterministic standards that apply to Ausgrid. Using a probabilistic process, AEMO found that one proposed substation could be safely deferred for up to 10 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 recent 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 from 2028. Several points might help explain these smaller results.

- The reliability reductions modelled by the AEMC might not have been very 'extreme'.[12] For example, Public Interest Advocacy Centre was 'surprised by the very modest reductions in customer reliability … that occur under the three scenarios modelled by the AEMC' (PIAC 2012, p. 4).
- The capital assets 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

12 The 'extreme' scenario was expected to result in 15 more minutes of outage a year. the Independent Pricing and Review Tribunal suggested the AEMC use more objective descriptors for the scenarios (IPART 2012d, p. 3).

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 those estimated 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.

Bolstering the STPIS

Removing *planning* standards altogether would increase the need for *performance* targets (the output measure) to be set efficiently, as well as the need for strong incentives to encourage businesses to provide levels of reliability to the point where customers' willingness to pay for additional incremental improvements is equal to the cost of its provision.

Establishing a national framework

Requiring distribution businesses to adhere to more than one set of performance targets increases the risk that businesses would inefficiently deliver reliability outcomes below (or above) the level for which customers are willing to pay. The AEMC (2012k) also points to potentially 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 targets 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). This option was put forward as part of the AEMC's suggested approach in its draft report of that review (AEMC 2012v).

However, retaining even some reliability requirements in jurisdictional codes and licence conditions inefficiently adds to costs for distribution businesses, which are passed on to customers, including:

- 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).

Therefore, all reliability requirements should be removed from distribution businesses' jurisdictional licence conditions, codes and regulations. (Safety related requirements should ultimately be encompassed in the national licence conditions, but with independent jurisdictional or national safety regulators ensuring compliance — chapter 11.) This would require the Standing Council on Energy and Resources to 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 distribution reliability outcomes to customers. Under this framework, the AER would set reliability targets using business-specific average past performance, and would set rewards and penalties using customer preferences specific to the region in which the business operates (these factors are discussed in detail below).

Harmonising parameters

Removing duplicated jurisdiction-specific reliability requirements, while at the same time ensuring that an incentive scheme is as effective as possible, requires that all parameters of the components in the STPIS be 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 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 those that 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.

Public reporting of performance (and possibly planning) would be likely to help to encourage an improvement in the performance of worst performing feeders, provided distribution businesses are responsive to public pressure and reputational consequences. Licence conditions that require businesses to supply connected customers, and develop contingency plans for how to deal with outages are also 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 as specified within the STPIS. 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. While the public reporting, licence and guaranteed service level provisions are likely to help encourage distribution businesses to address the concerns of worst served customers, the AER should continue to monitor this area and investigate adjustments to the STPIS if these arrangements were found to be ineffective.

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.

Importantly, it should be recognised that an efficient reliability framework would not give rise to 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. Further, as noted in chapter 14, for certain groups (such as those in rural or remote areas) reliability levels delivered commensurate with VCR may be viewed by society more broadly as unacceptably low (box 15.7). In these instances it is generally better for state governments to directly fund improved (above VCR) reliability levels directly through the use of Community Service Obligations rather than the alteration of particular standards or targets as has been proposed by the AEMC in its recent draft report of its review of distribution reliability outcomes and standards (AEMC 2012v). Using Community Service Obligations in this manner is both transparent and efficient (chapter 14).

Box 15.7 **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, and the price they are willing to pay for reliability to be improved. 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. A VCR framework would be likely to deliver significantly less reliability in more remote areas.

In most areas of essential service provision, society and governments have a desire to ensure some level of parity between rural and urban residents and thereby maintain a reasonable level of reliability for all. Responses to ensure that customers in rural and remote locations receive reasonable levels of reliability of electricity supplied through networks connected into the NEM have included specific reliability standards (including Guaranteed Service Levels) and requirements to connect new customers.

However, in these instances it is preferable for governments to directly fund improved (above VCR) reliability levels through the use of Community Service Obligations. The level of reliability that customers actually receive in these locations is therefore largely a question that should be determined by governments. In some cases it may be more efficient to improve reliability by means other than augmenting the network, such as through the installation of remote generation capacity.

Setting efficient targets

The reliability performance targets in the STPIS, based on historical performance, are unlikely to be efficient. However, given the demanding informational requirements and uncertainties, it is not trivial to set reliability targets at a level where the incremental costs and benefits of further improvements are aligned.

One issue 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 methodologies exist for estimating the marginal cost curves for distribution businesses in the NEM,[13] robust estimates are unlikely to 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.

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 15.5) and the initial targets are incorrect (box 15.6). To motivate this adjustment, the AER should issue the performance targets for businesses annually using a moving five-year average of past performance.[14] Box 15.8 sets out how the STPIS would iterate towards an efficient level of reliability using historical performance based target.

It should be noted that while using past performance avoids the complexity of determining a distribution business's marginal costs of improving reliability, difficulties in accurately measuring VCR remain.

Were the Australian Bureau of Statistics to conduct regular surveys of customers as recommended by the Commission (recommendation 14.2), 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 should (in theory) be possible to tell if the business has been performing

13 For example, Jamasb et al. 2010 estimate marginal cost curves for UK electricity distribution companies at an aggregate level.

14 The Energy Networks Association (sub. DR71) disputed the use of a five-year moving average target as they believed it would not be practical due to the lags involved in correcting reliability issues and the time taken for the results to be revealed. They argued that as a result of this, the ability for a distribution business to recoup the costs of an investment within the five-year regulatory control period was uncertain. However, even in the presence of such lags, actions by distribution businesses will be rewarded under a five-year moving average when the improvement in reliability is observed. Despite this, the improvement will not accrue reward payments for as long as under a fixed period system. The Commission does not see a justification for 'locking in' rewards within a set period if the VCR used to calculate rewards and penalties is set at the right level.

below (or above) the efficient level through its response to the incentive payments. If the business responds by improving performance, previous levels of reliability would have been inefficiently low. The change in reliability would eventually shift the targets up. Customers would then value further incremental improvements to reliability less, meaning the VCR estimated from subsequent surveys would fall. This process should iterate until the costs of an incremental increase in reliability were equal to the value customers place on that increase.

Box 15.8 **Adjusting to efficient targets and incentives**

Basing incentive payments under the STPIS on an accurate VCR should encourage distribution businesses to supply the efficient level of reliability across their networks. Under the proposed arrangements, the VCR (estimated at the feeder level) would be used to set the incentive payments/penalties, with caps on the aggregate reward or penalty imposed on a distribution business. Ex ante, the efficient target is not known, so that a moving average of historical performance would be used as the estimate of the efficient target.

The efficiency of the targets at the start would depend on the efficiency of the current reliability requirements. However, given distribution businesses are only rewarded or penalised by the amount customers value changes to reliability, they would start to move to more efficient reliability levels (and with it the target). For example, in a network where reliability standards were inefficiently high, the distribution business would chose to pay the penalty and reduce reliability levels, as the costs of maintaining the status quo would be higher than the penalty. On the other hand, if reliability levels were currently inefficiently low, then the costs of improving levels would be less than the reward payments, inducing improvements.

In response to these changes in reliability, however, customers would also adjust the value they place on further incremental changes in reliability. By taking regular surveys to identify these values and incorporating the updated values into the incentives, changes in how customers value incremental increases in reliability would also be captured in the incentive scheme. Together, these factors would mean the reliability performance of distribution business should iterate towards the efficient level.

These changes are not a significant shift for the AER or distribution businesses already operating under the Scheme and 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 by feeder type and based on the VCRs estimated by the Australian Bureau of Statistics as recommended in recommendation 14.2.

The Commission notes that its proposed approach differs from the proposals made by the AEMC in the draft report of its *Review of Distribution Reliability Outcomes and Standards* (AEMC 2012v). The AEMC proposed that distribution businesses be involved in setting targets based on disclosures of various options and their costs to the standard setter. While such an approach could, in theory, motivate an instantaneous shift to efficient reliability levels (the Commission's approach requires this to be revealed over a number of periods), it is likely that revelations of efficient reliability costs would be difficult and costly to obtain. Therefore, some iteration between periods would still be required. Given this, if the VCR used to determine incentive payments (and penalties) is correct, under the Commission's proposed approach distribution businesses would reveal the efficient level of reliability over time without the additional cost of a negotiation process between distribution businesses and the standard setting agency as proposed by the AEMC.

Ensuring incentives are strong

The transition path to efficient reliability targets will be slower under capped incentives penalties and payments. 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)

Some businesses, for example SP AusNet, preferred such uncapped two-sided incentives. 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 would 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', which comprise 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 should 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, avoiding the need for 'dead bands'.

An advantage of ensuring sufficiently strong incentives is that it encourages businesses to use their choice of inputs more efficiently to achieve 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 when 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 incentive of 5 per cent under the STPIS should therefore remain, the revenue at risk facing each business 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. This includes 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 close to being classified as 'major events').

RECOMMENDATION 15.1

All jurisdictions should adopt the Australian Energy Regulator's Service Target Performance Incentive Scheme as the basis for setting efficient reliability requirements for distribution businesses. The Scheme should replace all existing jurisdiction-specific distribution reliability requirements.

RECOMMENDATION 15.2

The Australian Energy Regulator should 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 a rolling five-year average of annual performance***
- ***incentive payments for deviations from the reliability performance targets should reflect the preferences of customers by using the estimated values of customer reliability, as spelt out in recommendation 14.2, and should be specific to the distribution business***
- ***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.***

16 Transmission reliability and planning

Key points

- Reliability settings for transmission networks in the National Electricity Market (NEM) are a key determinant of network design, performance and cost.
- Setting reliability in transmission is complicated by inherent problems not present in distribution networks, such as network inter-linkages between regional service providers, difficulties observing latent levels of reliability and a high cost of failures.
- The special features of transmission networks require that incentive regulation used in the NEM be complemented by reliability standards (instead of reliability targets as recommended for distribution networks) to achieve efficient outcomes.
- There are three quite different reliability standards currently used in the NEM: deterministic standards, probabilistic planning and hybrids of the two. All involve inefficiencies.
- Moving to a NEM-wide transmission reliability framework, underpinned by probabilistic cost–benefit informed standards is conservatively estimated by the Commission to generate large efficiency gains of $2.2 billion to $3.8 billion over 30 years.
- The Commission's proposed framework (the PC model), to be implemented NEM-wide, comprises:
  - A new NEM-wide reliability framework in which the Australian Energy Market Operator (AEMO), uses enhanced probabilistic planning methods and values of customer reliability to set cost–benefit based standards at the connection point level, and develops its National Transmission Network Development Plan.
  - Transmission service providers undertaking a robust cost–benefit analysis of large proposed augmentation and replacement investments (over a threshold value).
    - These would be pursued through an enhanced Regulatory Investment Test–Transmission process where revenue determinations are made by the Australian Energy Regulator (AER), with input from AEMO, prior to investments taking place.
    - Projects under the threshold would be funded through the general AER revenue allowance and be subject to the workings of incentive regulation.
  - AEMO acting as the planner of last resort where it considers underinvestment could put at risk efficient levels of reliability.
- The benefits of the PC model would be severely undermined if standards were set at a jurisdictional level. If this were to occur, the AEMO planner model would yield greater gains than the proposed approach.

16.1 Introduction

The transmission network represents the 'backbone' of the NEM, and is the conduit through which most electricity is transferred from generators to distribution networks, and ultimately, to the consumer. It is therefore important that it is reliable.

There are two main concerns about transmission reliability.

First, there is a contemporary concern that, outside Victoria, reliability standards, combined with state-ownership of transmission network service providers (TNSPs), has led to excessive investment. Reliability settings are a major driver of the costs of investment in transmission networks (AEMC 2008a).[1] The AER has been 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:

> … 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, p. 14)

Second, there is a concern to ensure that future arrangements result in adequately reliable transmission networks. There are three main risk factors that, unless tempered by an appropriate reliability framework, could potentially lead to underinvestment. These include the:

- desirable shift away from prescriptive deterministic reliability standards
- presence of more commercially TNSPs (whether achieved through privatisation or better governance of state-owned network businesses)
- ongoing application of incentive regulation.

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1 For example, the AER recently approved more than $2 billion in capital expenditure for load driven augmentations and replacements in Powerlink's latest revenue determination (2012 to 2017).

2 'The Group' includes Loy Yang Management Company, AGL Hydro, International Power Australia, TRUenergy and Flinders Power.

There is already broad agreement among most stakeholders, including all governments, that the current reliability framework has provided scope for some TNSPs to make inefficient investments, with a shift away from prescriptive standards seen as desirable. Given this, the emphasis of this chapter is on the second concern focusing on reliability settings within future transmission planning frameworks.

Any assessment of reliability settings within future transmission planning frameworks must consider the:

- special features of transmission networks (section 16.2)
- broader planning context and economic regulation (section 16.3)
- appropriate criteria for making judgments about the most efficient framework (section 16.4).

The chapter then draws conclusions about the desirable characteristics of a new framework for transmission reliability in the NEM (section 16.5). Operational and performance standards are addressed briefly towards the end of this chapter (section 16.6). A summary of the proposed transmission planning reforms is then outlined in section 16.7. A proposed new approach for new connections and other separable investments is also put forward (section 16.8). The approach is underpinned by findings from detailed analysis of current and proposed (albeit fluid) models for transmission reliability and planning, which are presented in appendix F. Appendix F also contains a full description and analysis of existing systems, along with recent models proposed by the Australian Energy Market Commission (AEMC) and Grid Australia, the latter in response to the draft report of this inquiry.

16.2 The special characteristics of transmission networks

The approach to planning and reliability setting for transmission networks needs to overcome a number of inherent problems that are not present in distribution networks.

- The need for NEM-wide planning. This reflects that transmission investments and reliability settings in one jurisdiction can affect other parts of the network in that jurisdiction, and that investments to address constraints in one transmission business' network might be more efficiently made by another TNSP in another jurisdiction.

- The difficulty of observing the *latent* vulnerability of the transmission system to major outages. The majority of power interruptions that customers experience within the 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' (AER 2011e, p. 2). However, the low number and short duration of outages at a given time can lead to false optimism about the inherent reliability of the network over time. Moreover, the scale of transmission networks mean that any prolonged network failures can have widespread and very costly effects (box 16.1). This means that a transmission system must be planned to reduce the risks of future major network failures. In that respect, concerns about transmission network reliability are akin to those relating to the safety of major chemical plants or nuclear power stations, where the goal is to prevent major incidents.

These characteristics mean that it is not possible to rely on conventional incentive regulation alone to ensure efficient outcomes in transmission as:

- TNSPs are set up on a regional basis and will have a tendency to only consider NEM-wide effects (or lack thereof) of investments to the extent they influence their business — and may not sufficiently account for the costs of cascading failures or the efficient location of investments within the NEM as a whole
- privately-owned TNSPs will likely plan for reliability based on the commercial risks they face from having to compensate customers for outages, the loss of reputation and the possible loss of their license to operate. But they have limited liability. This weakens their incentives to make very large investments to prevent extremely high cost, low probability events, whose costs would not be fully borne by the business. It seems unlikely that a business' board would make the same decisions to mitigate the risk of an event that produced costs equivalent to the business' market value and one that produced costs 10 or 100 times the business' market value (creating a wedge between privately optimal investment and socially optimal investment)
- privately-owned TNSPs have an incentive to put forward large investment proposals to the regulator for ex ante revenue determinations and to then delay investments necessary for reliability purposes in order to increase their profits. It is difficult to distinguish between profits acquired from strong efforts by the business to minimise the costs of achieving a given reliability standard (the goal of incentive regulation) and profits acquired from the inefficient deferral of investments needed for maintaining the inherent reliability (or indeed safety) of the network

- it may be difficult to hold TNSPs accountable for failures in network reliability since some factors affecting system reliability lie outside the control of the network business (such as major natural disasters).

To overcome this, Australian governments have set reliability standards for transmission networks, rather than relying exclusively on incentive regulation. (Setting reliability standards brings with it a number of other issues — see below.) These characteristics also mean that the best approach to ensuring efficient levels of reliability within distribution networks is not transferable to transmission.

Box 16.1 **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).

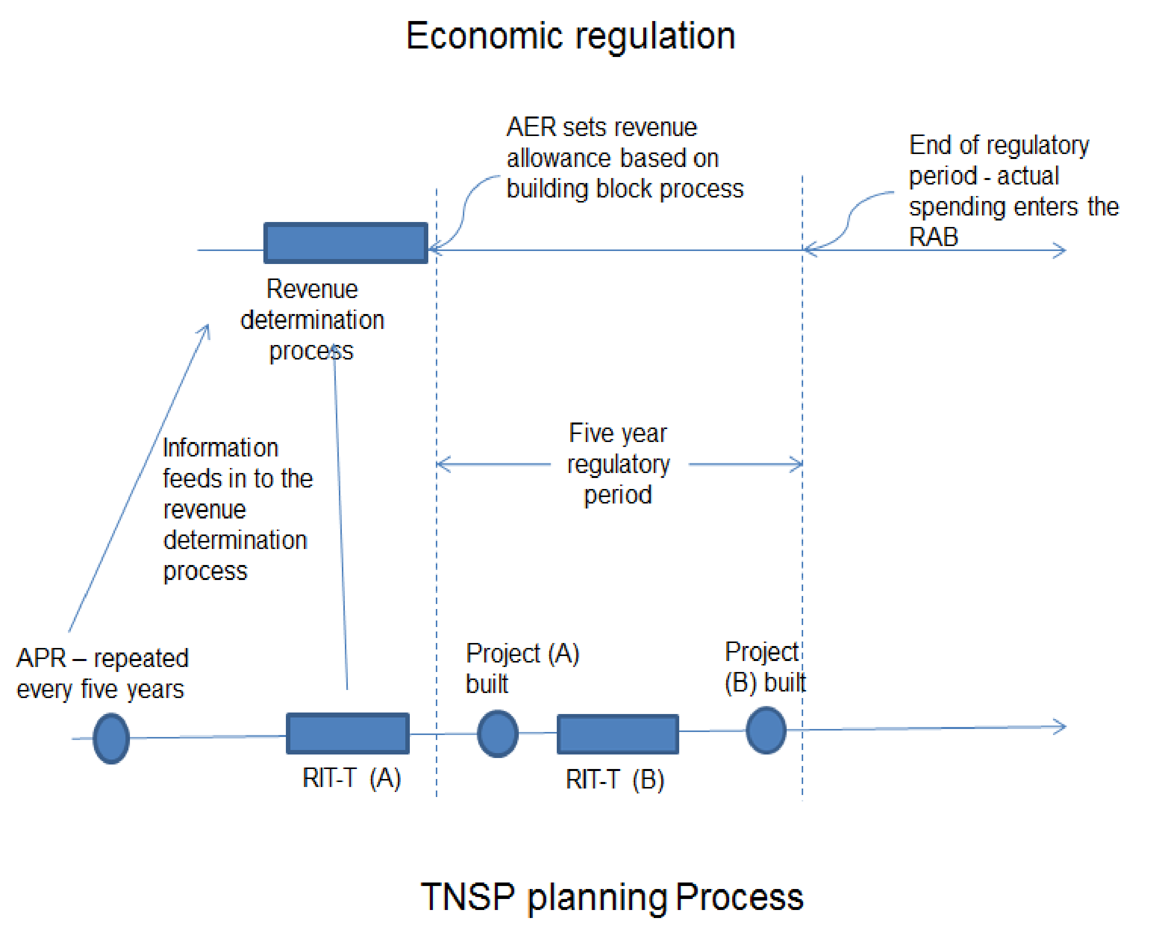
- A blackout in Italy and Switzerland (28 September 2003) which affected 56 million people for 48 hours was caused by the operational overloading of a transmission line in Switzerland on a hot day, causing the line to sag and arc to the trees below. Power flows on the inter-network connections between 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, which resulted from 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).

16.3 The broader planning context and economic regulation

Reliability standards are just one component of a complex system of economic regulation and planning (including the Regulatory Investment Test For Transmission (RIT-T) — box 16.2 and chapter 17). Decisions about how to regulate reliability will have broader implications for economic regulation and investment planning (and vice versa) (figure 16.1, which applies to jurisdictions other than Victoria).

Economic regulation is centred on the revenue determination process, undertaken using the building block methodology (chapter 5). 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 the TNSP build any particular project.

Figure 16.1 **Parallel processes — economic regulation and planning**



Source: Based on AER (per. comm., 20 September 2012).

Box 16.2 The role and application of the RIT-T

The RIT-T, 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 for several reasons (discussed further in chapter 17).

- Benefits do not have to outweigh costs for a project to ‘pass’ if the augmentation is being built to meet a reliability standard.
- The transmission business intending to undertake a project carries out the RIT-T — not an independent party.
- The details of alternatives canvassed in the RIT-T (and their costs and benefits) 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. These incentives will not be overcome by any requirements in the RIT-T.
- There is no substantive consequence for the TNSP from producing an inadequate RIT-T.

The RIT-T also has little role in the AER’s revenue determination process for transmission. The only role of any RIT-T is that the business must include any augmentation option that has passed a RIT-T in its aggregate capital expenditure (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 over the regulatory period. Under that approach, the business must build to meet any specified reliability 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 undertaken.

This is not to say that the RIT-T has no impact or should be discarded. Even if it does not overcome all information asymmetries between the prospective investor and other stakeholders, the Test is still able to shed some light on egregious examples of gold plating, or unjustified preferences for network-based solutions, or intra-jurisdictional preferences. Further, it provides a platform for public consultation of possible alternative options, especially for demand management options. However, as discussed in chapter 17, there are strong grounds for improving the Test.

The ‘RIT-T’ as undertaken by AEMO in Victoria has a different role. In this case, it is an independent cost–benefit analysis that determines the nature of the solution (which might not be capex) and the required 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, options, timing, costs and network-wide needs.

As shown in figure 16.1, information from planning processes (which include Annual Planning Reports and the RIT-T) feed in to the revenue determination process, but is only used to inform the process, and is not used in a way that ‘locks in’ any particular investment. In the example in figure 16.1, information from the RIT-T for project A (which is due to be built in the regulatory period) is available as an input into the AER’s revenue determination. It is not possible to use information from the RIT-T for project B as it has not been prepared at the time of the determination. Instead, the Annual Planning Report would identify a network need, for which reliability standards are a key determinant, and the estimated cost of efficiently meeting the need would be included as part of the overall figure set by the revenue determination.

Under incentive regulation, there is no requirement that expenditure proposals used to inform revenue determinations actually materialise. 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 (RAB) for the next revenue determination. Indeed, neither the RIT-T, nor the planning process, directly determine the revenue allocated to a TNSP by the regulator.

16.4 An efficient transmission framework?

Within the NEM, each jurisdiction has a separate planning framework for setting reliability standards for transmission businesses (table 16.1). The frameworks vary in the:

- 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 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.

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 Council of Australia Government (COAG) Independent Review of Energy Market Directions in 2002 noted that it was ‘very much aware of community and hence government sensitivity to issues of supply reliability’ (MCE 2002, p. 8), which underpinned the reluctance of governments to relinquish control of reliability settings in their networks.

Table 16.1 **Transmission network reliability standards under existing planning frameworks**[a]

State	*Type of standard*	*Standard*	*Source of standard*
NSW	Deterministic	N-1 everywhere, except central business district 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 central business district has the highest VCR)	Sections 50C and 50F of the National Electricity Law
Qld	Deterministic	N-1 everywhere but also 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 (revised to five from July 2013) 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 the Essential Services Commission of South Australia with advice from the AEMO
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 appendix F and VCRs are discussed in chapter 14.

Source: AEMC (2008a, pp. 171-4).

While significant variations between jurisdictions exist, it is possible to assign each jurisdiction's planning framework for setting transmission network reliability standards into one of three broad categories:

- deterministic standards in New South Wales, Queensland and Tasmania
- probabilistic planning in Victoria
- 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 2008 *Towards a Nationally Consistent Framework for 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).[3]

Approach to assessing frameworks for reliability settings

The efficiency of reliability standards within transmission planning frameworks can be assessed in four main ways, including:

- their impacts on a TNSP's efficient choices about the various options for meeting reliability standards and their optimal timing
- whether the standards are set using a methodology based on the value consumers place on reliability (chapter 14)
- their administrative and compliance costs
- the extent to which a reliability framework allows businesses to make excess profits that do not reflect innovation or efforts to minimise costs (termed windfall gains by Grid Australia (sub. DR91, p. 18)).

A comprehensive assessment also requires taking into account the innate characteristics of transmission networks as spelt out in section 16.2.

These characteristics require that the efficiency of reliability planning frameworks is assessed with a NEM-wide perspective including by considering how well the frameworks:

- assist with the national operation of the 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 the degree to which the frameworks need to incorporate auditing of facilities and processes in transmission networks to assess the latent and actual reliability of networks. This reflects the difficulties in using current reliability performance as a guide to latent reliability (section 16.2). Therefore, the only way of accurately assessing the inherent reliability of such networks is to:

- specify in some way what needs to be done to achieve a given level of reliability

3 In the final stages of preparing this report the AEMC released an issues paper for it review of National Frameworks for Transmission and Distribution Reliability (AEMC 2013c) which canvasses many of the issues discussed in chapter 14, 15 and this chapter.

- 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 to simply 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 six broad criteria:

- *efficiency in investments* — under- and over-investment, along with optimal investment timing
- *efficiency of standards* — whether standards are set by determining the level of reliability that provides net benefits for customers
- *minimising administrative and compliance burdens* — costs imposed on market participants and regulators
- *minimising windfall gains* — whether it is possible to avoid windfall gains (or losses) from ex-ante revenue settings reliant on demand forecasts that may not eventuate
- *NEM-wide effects* — whether efficient investment location in the NEM is considered, along with other NEM-wide risks such as cascading failures
- *auditing compliance to ensure reliability and efficiency in the long run* — overcoming the inability to observe differing levels of reliability and ensuring that, where circumstances have not changed, proposed investments take place.

Current approaches vary and have drawbacks

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 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 that 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 no single perfect solution.

Assessments of the current approaches to transmission reliability across the NEM (appendix F) reveal a number of shortcomings of the current approaches.

- The deterministic standard systems used in New South Wales, Queensland and Tasmania provide weak incentives for TNSPs to adopt the cheapest solutions to address identified network constraints, are unlikely to identify efficient reliability standards and do not consider NEM-wide effects. However, they do have low administration and compliance burdens. Shifting away from deterministic standards towards a probabilistic cost–benefit framework could produce net present value savings in the realm of $2.2 billion to $3.8 billion over a 30 year period (appendix F).
- Victoria's planner model performs well against many of the criteria. AEMO's joint role as Victorian planner and operator means that NEM-wide effects are incorporated into investment decision making, albeit to a limited extent. The model should ensure that network constraints are resolved without over-investment, given independent cost–benefit analysis of prospective solutions to network constraints and the adoption of a probabilistic approach to standards. Contestability for separable investments (section 16.8) creates strong incentives for businesses to provide solutions at the lowest cost to customers. And for non-separable augmentations, once AEMO and the transmission business identify a required investment and have negotiated payments, cost savings by the business translate into higher profits, creating incentives for cost minimisation at the project level. However, the incentive regulations overseen by the AER do not apply for network augmentations in Victoria. Furthermore as a not-for-profit entity, AEMO does not face any direct financial incentives to find innovative ways of resolving network constraints without costly investments. On the other hand, it has no direct financial incentives to 'gold-plate' or defer necessary investments. Administration and compliance costs are also likely to be higher than the deterministic approach used in New South Wales, Queensland and Tasmania. Further, a number of improvements to the current probabilistic planning approach could be adopted.
- The hybrid approach used in South Australia is likely to reduce the risk of over-investment because of its use of probabilistic cost–benefit estimates for determining reliability standards. On the other hand, the approach may still risk some over-investment. First, it involves the translation of probabilistic estimates (based on Victorian customer reliability values) into deterministic standards that are expressed in excessively broad categories. Moreover, while the standards may rise as circumstances change, they cannot be revised down. Administration and compliance costs are likely to sit between the other approaches and, as in Victoria, AEMO's involvement is likely to lead to NEM-wide effects being indirectly included in reliability planning.

None of the current approaches addresses concerns about auditing and compliance and, with the exception of Victoria, does little to minimise any windfall gains or losses from revenue determinations based on demand forecasts that may not eventuate. Outside Victoria, TNSPs have the incentive to attempt to justify inefficiently costly expenditures in order to meet reliability standards.

The assessment of the existing planning frameworks for transmission reliability against the criteria noted above provide a number of lessons for the development of a new national framework. These are outlined below.

Efficiency of investments

- Commercially-orientated businesses with strong incentives to cost minimise (once committed to action rather than simply deferral) 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 adopted, 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 close to their commencement, and approving the associated revenue allowances for projects based on this knowledge, can help deliver cost savings to customers.
- Competitive tendering of separable investments may reduce (net) costs and encourage 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 and timing to deliver reliability benefits.
- 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 choices.

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 foreseeable 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 for the NEM should be determined by an independent, non-conflicted, well-informed third party. Decision making about augmentation, replacement and maintenance should rest with TNSPs due to potential synergies in jointly planning these activities. There should, however, be external oversight of decisions for large projects. For smaller projects, there are grounds for TNSPs to undertake probabilistic analysis for determining the best way of meeting externally set customer-driven reliability standards without detailed external oversight of all augmentations due to the potential administrative costs involved.
- 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.

Minimising windfall gains

- A planning framework should avoid, where possible, large transfers that might arise from revenue determinations based on demand forecasts that do not eventuate while keeping the cost minimisation and innovation incentives of the incentive regulatory framework intact. Given the possible price and therefore consumption distortion effects of large transfers to TNSPs due to the large and lumpy nature of some augmentation investments, critical and contemporary reviews of major investment decisions should occur to minimise the potential for large windfall gains.

Taking account of NEM-wide effects

- A planning framework should consider the costs and benefits of the effects that reliability settings in one area of the network can have on another (that is, network effects). As put by AEMO, a national planning approach ensures that interconnectors are viewed as part of the meshed intra-regional transmission networks that they connect (sub. DR100, p. 10).
- 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 increasingly 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 under-investment 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.

16.5 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.

There has been a recent broad acceptance of the assessment that deterministic standards have an inherent potential to generate inefficient outcomes if not underpinned by a consideration of the value consumers place on reliability. This has led most stakeholders and governments, to varying degrees, to acknowledge the need to move to a reliability planning framework that is based on an economic cost–benefit framework — namely a probabilistic planning approach. For example, COAG stated that the national framework, developed by the AEMC should:[4]

> … incorporate values of customer reliability and differences arising from geographical location. (2012, p. 9)

Grid Australia also supported a national move to a framework where reliability standards were determined with consideration of their costs and benefits:

> … there are many aspects of the Commission's report that Grid Australia supports, including: … The approach to setting planning standards in each jurisdiction should be improved and a new approach is needed that properly considers the full economic costs and benefits of network investment. (sub. DR91, p. 6)

This change, if adopted, should overcome inefficiencies in reliability standards. Indeed, in a high-level review of existing projects for 2012-13 ($3 billion worth of projects) focusing on differences in investment timing between deterministic standards and those based on an economic cost–benefit framework, AEMO found that annual electricity bills for households in 2012-13 could be at least $40 per customer too high:

> AEMO compared the timing of augmentations proposed by the TNSPs, applying existing planning criteria requiring a specific reliability outcome, with investments that are timed to deliver a better price-service balance for customers. The high-level study into the benefits of an economic cost–benefit approach to network investment showed that there are significant savings that could be achieved.

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4 SCER issued the AEMC with a terms of reference for a review to develop new approaches for the regulation of electricity distribution and transmission reliability across the NEM which incorporate the value customers place on reliability on 14 February 2013 (SCER 2013b).

> The study indicated that 2012–13 electricity bills may be at least $40 per customer, on average, too high because current electricity investment is based on reliability in isolation of cost and the type of investment and would defer most augmentation timings.
>
> AEMO believes that an economic approach is expected to deliver even greater savings to electricity consumers in the long term by providing more time to develop new generation and transmission solutions and technologies; and accommodate changes to demand profiles, acknowledging a more energy-conscious community. (sub. DR100, p. 5)

There is, however, some contention over the best way to implement a probabilistic planning approach. The principal debate relates to who undertakes the augmentation (and replacement) investment planning and puts forward the suggested options. (Under a probabilistic framework used to set standards the term ‘planning’ can become confusing — box 16.3.)

Box 16.3 **The term ‘planning’**

Under probabilistic cost–benefit informed standards, what is meant by reliability ‘planning’ is not always clear. A significant degree of network planning must occur to identify the standards at a connection point level. This involves comparing the value of customer reliability with the costs of various investment options to achieve the most efficient reliability settings for the network.

Under such a system, certain planning activities are also conducted by TNSPs. To meet standards, TNSPs have to determine investment options, timing (subject to external review in some instances) and integration with other maintenance and replacement activities. These latter aspects have been termed ‘TNSP planning’ under the proposed model put forward in this chapter.

Grid Australia has argued that having TNSPs undertake network reliability planning subject to independently set standards would generate the greatest gains:

> We maintain that electricity consumers are better served by adopting a nationally consistent arrangement involving transmission asset owners retaining responsibility for augmentation investment decisions in the shared transmission network. (trans., p. 289)

The AEMC also supported this view, stating that it:

> … considers that financial incentives are likely to provide the most robust and transparent driver for efficient decision-making, as efficient outcomes can best be promoted by aligning the commercial incentives on businesses with the interests of consumers. (sub. DR89, p. 7)

AEMO agreed that arrangements along the above lines are likely to be a substantial improvement on the current situation (sub. DR100, p. 5). Nevertheless, AEMO's preferred position (articulated most fully in its first submission (sub. 32)) is that planning should be undertaken by a NEM-wide central planner to ensure efficiency across the entire network:

> Australia's transmission regulation and planning regime must optimise network development on a national basis to deliver the most efficient response to the challenges of the future. … Independent planning coupled with the competitive provision of network services will deliver the most efficient outcomes. (sub. 32, p. 4)

In the Commission's view, the most efficient model would draw on both the original AEMO and the new Grid Australia/AEMC approaches (a summary of the existing and proposed models is provided in table 16.2). Transmission businesses would be free to undertake augmentation (and replacement) investment planning subject to independently set national reliability planning standards, but with all planning underpinned by probabilistic cost–benefit assessments. This model corrects some of the deficiencies of the current approach in Victoria and that of the proposed AEMC's hybrid[5] and Grid Australia (sub. 91, pp. 10-38) models. The relative costs and benefits of the proposed approaches, along with existing reliability planning models are assessed in appendix F.

The Commission's national transmission probabilistic reliability standards model (the 'PC model')

The Commission's proposed model — set out in greater detail in figure 16.2 — could overcome many of the issues identified with the current reliability planning approaches. The PC model seeks to improve national oversight of transmission planning, making TNSPs more accountable (a concern raised by AEMO (sub. DR100, p. 5) Grid Australia (sub. DR91, p. 10); and SP AusNet (sub. DR99, p. 3)).

5 This was set out in the second interim report of the Transmission Frameworks Review (AEMC 2012j) and the Transmission Reliability Standards Review (AEMC 2010a), the latter of which was largely endorsed by the MCE (2011).

Table 16.2 **Current and proposed transmission planning models**

	Deterministic standards model (NSW, Qld & Tas)	*AEMO planner model (Vic)*	*Hybrid standards model (SA)*	*AEMC hybrid model*	*Grid Australia's model*	*PC model*
Type of reliability standard or planning?	Deterministic	Probabilistic planning	Probabilistic planning informed deterministic standards (applied to 6 connection point categories) subject to no downward revision requirements	Hybrid standards for connection points	Probabilistic cost–benefit standards expressed deterministically	Probabilistic cost–benefit standards expressed deterministically or probabilistically
Standards contained in?	State-specific regulations and licence conditions	Not specified but most likely reliability to become a national function	Electricity Transmission Code administered by Essential Services Commission of South Australia with advice from AEMO	National template and/or jurisdictional instruments. Reliability to remain as a state and territory function	Reliability to become a national function	Reliability to become a national function
Who sets the standards?	Jurisdictions	AEMO	Jurisdiction	Jurisdictions with input from expert advisor	Independent body in consultation with consumer representatives and stakeholders	AEMO in consultation with transmission businesses
Who makes augmentation investment decisions?	Transmission businesses	AEMO	Transmission business	Transmission businesses	Transmission businesses with oversight of AEMO and AER	Transmission businesses with oversight of AEMO and AER

(Continued next page)

Table 16.2 **(continued)**

	Deterministic standards model (NSW, Qld & Tas)	*AEMO planner model (Vic)*	*Hybrid standards model (SA)*	*AEMC hybrid model*	*Grid Australia's model*	*PC model*
Process for planning or setting standards?	Set at level deemed appropriate by jurisdictional standard setting body	AEMO probabilistic planning process	Historical deterministic levels with upwards revision based on probabilistic analysis	AEMO to develop national template. Standards to be 'informed' by jurisdictionally appointed body	Independent body to apply best practice probabilistic cost–benefit assessment in consultation with consumer representatives and stakeholders	AEMO probabilistic planning process, based on ABS data, peer reviewed and designed to be international best practice
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.	AER five yearly revenue determination process	AER five yearly revenue determination process	Combination of AER five yearly revenue determination process and contingent projects subject to 'trigger' criteria	Improved RIT-T process for large projects above threshold before start of project. AER five yearly review for below threshold projects
Independent cost–benefit analysis or RIT-T?	Businesses to conduct RIT-T (net costly augmentations possible if justified to meet reliability standards)	Independent cost–benefit analysis	Businesses to conduct RIT-T (net costly augmentations possible if justified to meet reliability standards)	Businesses to conduct RIT-T with scrutiny by AEMO	Businesses to conduct RIT-T with scrutiny by AEMO and oversight by AER	Business to conduct cost–benefit analysis through improved RIT-T with scrutiny from AEMO whose advice takes presumptive force and approval by the AER
Last resort planning power	AEMC	AEMC	AEMC	AEMO	AEMO	AEMO

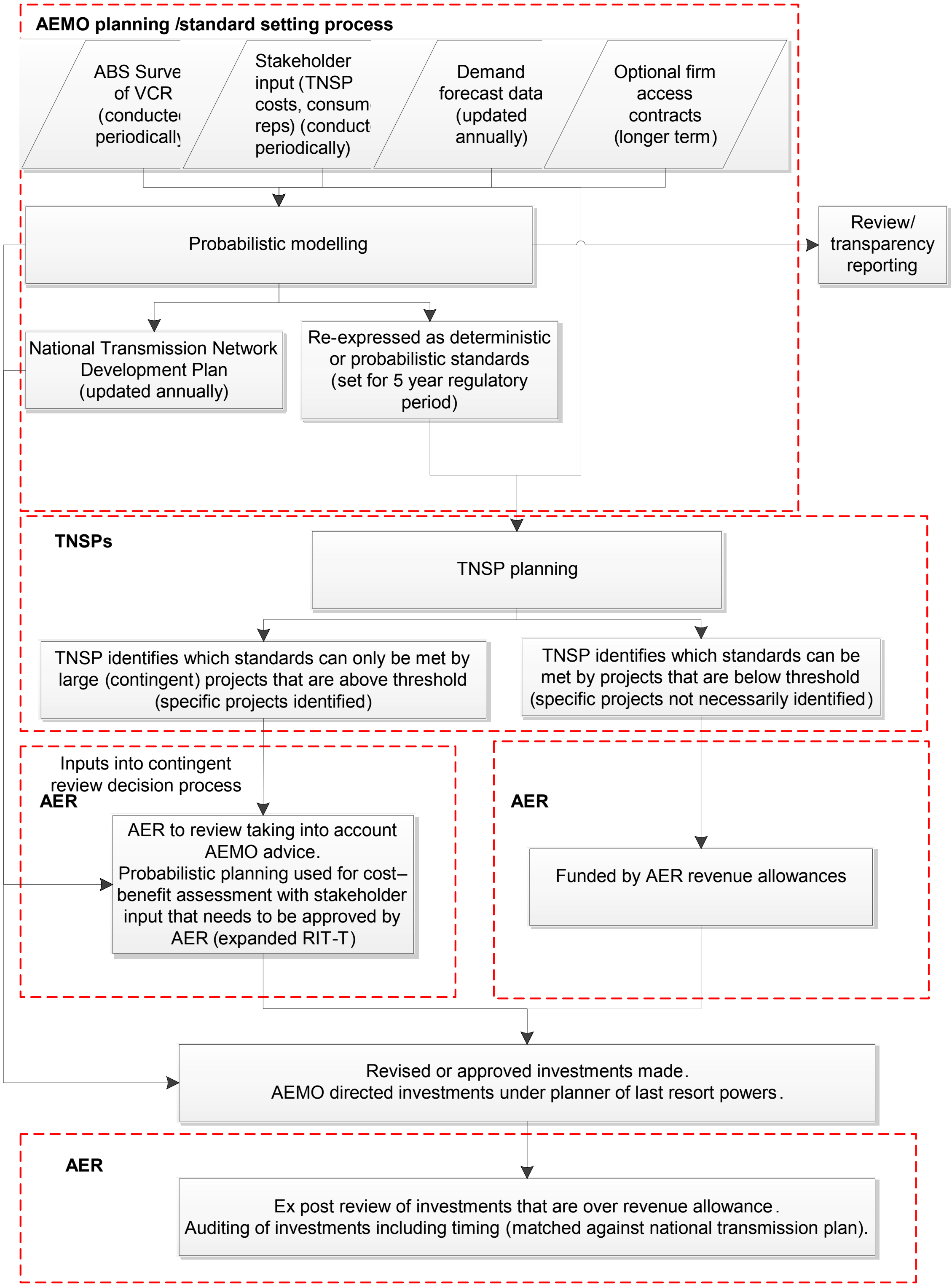
AEMO sets standards using a probabilistic approach

On a NEM-wide basis, AEMO should undertake probabilistic cost–benefit analysis using VCR estimates obtained from the ABS (recommendation 14.2) and input from distribution businesses on demand forecasts to develop a reliability standard at each connection point. The standards could be expressed in the same manner as existing deterministic standards (the N-x formulation). Alternatively, they could be expressed in other ways, such as the probability-weighted quantity of electricity at risk — the approach taken by Victorian distribution business (AEMC 2012k, p. 81). Distribution businesses should also be consulted on standards for the connection points that link their network with the transmission grid.

AEMO should revisit this analysis periodically. AEMO's probabilistic analysis as currently used in Victoria, and to a lesser extent in South Australia, should be improved to include the following:

- Greater scrutiny over its process, through regular reporting of modelling parameters, assumptions and results, and data inputs to the AER. This would include releasing details of the estimated amount of load customers were willing to lose at any connection point, based on the estimated VCR, before any reliability increase or augmentation needed to be considered (AEMO, sub. DR100, p. 5). Periodic review would also be appropriate to ensure that the standard setting framework was delivering optimal outcomes in accordance with the National Electricity Objective (NEO).
- An enhanced process for probabilistic analysis — assessed through periodic peer review — to ensure that the analysis represents international best practice. One of the first steps is to identify the deficiencies in the data collected by network businesses and AEMO, and establish the required collection and reporting processes.
- The use of disaggregated VCR estimates, including by geographical location, customer type and interruption duration. 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 14.2). The VCR surveys would be undertaken periodically, with AEMO's annual probabilistic analysis and planning based on extrapolated data for periods between the survey dates.

Figure 16.2 **The PC model**



An annual National Transmission Network Development Plan would guide TNSPs and the AER

The probabilistic planning approach that AEMO uses to establish reliability standards in the NEM should also form the basis of the annual National Transmission Network Development Plan (NTNDP). This would provide a critical input into the planning undertaken by TNSPs and in the assessments made by the AER. The probabilistic modelling would be undertaken in depth every five years, but with annual updates based on more simple analysis to test whether standards are too low or high at critical connection points.

Investment decision-making would depend on the scale of the investments

Once standards are set, TNSPs should undertake reliability planning of their networks with reference to the NTNDP. This would have two components.

Identified augmentation and replacement projects less than a certain threshold (see chapter 17 for details on what might be an appropriate threshold) would be undertaken by the TNSP without direct AEMO or AER oversight. The required revenue to fund these projects would be drawn from the aggregate revenue determination made by the AER at the start of the regulatory period. The TNSP would not be obliged to specify these projects in detail at the time of the revenue determination. Instead, as is currently the case, for any given regulatory period, the TNSPs would propose a set of capex and operating costs (opex) necessary to supply reliable power over the next five-year period, without any commitment to undertake any specific projects that might form part of its revenue proposal. However, at any time, it would be obliged to be able to demonstrate that it met the reliability standards translated from AEMO's probabilistic analysis.

In contrast, the process for approving identified augmentation and replacement projects greater than the identified threshold would draw on aspects of the current arrangements for so-called 'contingent' projects.[6] Investments would be assessed

6 Under the Rules, a contingent project is defined as a project assessed by the AER as reasonably required to be undertaken, but which is excluded from the ex-ante capital expenditure allowance in a revenue determination because of uncertainty about its requirement, timing or costs (AER 2007c). The Commission recognises that the current contingent project arrangements were designed for a different purpose than that envisaged by the Commission for large reliability-related expenditures. In particular, under the Commission's proposed arrangements, there is no requirement for any uncertainty about the costs, timing or need for the project. Accordingly, a large project would still be treated as 'contingent' even if at the time of the regulatory determination, AEMO's NTNDP suggested that it was *certain* that the project would be needed some time in the coming regulatory period. The required revenue for such a project

through an improved RIT-T process and revenue to fund the project would be determined and provided outside the general revenue determination process (as is currently the case for network augmentations in Victoria).

An improved RIT-T process

The improved RIT-T process would require a full probabilistic cost–benefit analysis of the investment, including an assessment of network and non-network options. The RIT-T would only be approved by the AER if projects were shown to generate net benefits estimated using current information (a shift from the process-based approval under the existing RIT-T). The AER would also determine the allowable revenue on a project-by-project basis. As the RIT-T is a full cost–benefit analysis, it would effectively reassess the reliability standard for that part of the network.

It would be important to mirror the current risk sharing arrangements present in general revenue determinations to avoid cost-shifting between large projects and those covered by the general revenue allowances. Accordingly, if a business were able to undertake a large project at less than the negotiated cost, then it would be able to keep a proportion, but not all, of the gains (as is the case in general revenue determinations — chapter 5). Similarly, if a TNSP were to spend more than the negotiated amount for a large project, it would be penalised by a share of the cost overrun. TNSPs would also be potentially subject to an ex post review process by the AER if its expenditures exceeded those set out in the approved RIT-T. In the case where the AER identified investments that exceeded the approved capital and were built too early (for example, an investment that was built to a higher capacity than would have been required to efficiently meet the constraint), inclusion of the higher capital costs in the RAB should be deferred until such time that the investment would have been beneficial. For cost overruns, only efficient investment expenditure would be included in the RAB.

The AER must also accept the advice from AEMO about the need for, timing, scale, choice and costs of the project, unless the TNSP could provide sufficient evidence to refute its finding (that is, AEMO's advice would have presumptive force). Projects approved through the improved RIT-T process would have an allowed revenue approved for the current regulatory period, with the value of the assets (less any depreciation) rolled into the RAB at the commencement of the next regulatory period (provided there were no inefficient cost overruns disallowed by an ex post review — see chapter 17 for more details on the improved RIT-T process).

would be appraised in a process separate from the general revenue determination process, and at a time close to the investment process commencing.

A safety valve to ensure a reliable system

AEMO should become the planner and procurer of last resort and seek to augment the transmission network if it identified investments to meet reliability standards that were *net beneficial* for the NEM and were not being undertaken by the regional TNSPs. AEMO would have the power to direct a TNSP to act or seek to procure from the market an augmentation to satisfy any reliability constraint identified. The AER would be the arbitrator of any disputes between TNSPs and AEMO.

The costs and benefits of the proposed approach

The proposed PC model is *designed* to score well against the assessment criteria for an optimal reliability framework (table 16.3).

Table 16.3 **How proposed transmission reliability planning models score against the assessment criteria**
Indicative NEM-wide result

	Efficiency of investments	*Efficiency of standards*	*Minimising admin and compliance costs*	*Minimising windfall gains*	*Taking account of NEM-wide effects*	*Auditing compliance to ensure reliability and efficiency*
AEMC model	→	→	→	→	→	
AEMO planner model (Vic)	→	→	→	→	→	
Grid Australia model	→	→	→	→	→	
PC model	→	→	→	→	→	→

Source: Based on analysis in appendix F and this chapter.

- *The model reduces the risk of under-investment for large reliability driven investments.* Several factors are pivotal in achieving this outcome. First, as TNSPs no longer access revenue at the start of a review period for large projects, there are no benefits from deferring large investments needed for reliability purposes. The enhanced RIT-T approach would provide flexibility to shift the timing of investments when circumstances change, as the standard itself, and therefore investment need, is reviewed just prior to project commencement. Only net beneficial projects, assessed with current information, would be approved — a form of a 'real options' approach to planning.[7] Second, explicit standards

7 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

provide clear guidance about what standards must be met. Finally, AEMO's last-resort planning and decision-making powers provide a safety valve in case of significant mistakes by TNSPs. An Achilles' heel of the model may be that it does not necessarily guarantee sufficient investment for projects below the threshold. However, the TNSPs would still be obliged to meet standards and to meet the costs of system failures if it did not do so.

- *Standards are efficient*. The determination of standards based on probabilistic cost–benefit analysis at the connection point minimises the 'lumpiness' of applying standards compared with models that make use of a limited number of connection point categories to which standards are uniformly applied (as exists in AEMC's proposed model and in South Australia's current approach). It therefore reduces the risk of inefficiently high reliability investments. Further, standards would be allowed to rise or fall over time depending on VCR, overcoming the issues that exist with South Australia's hybrid model. Looked at in isolation, the PC's model *appears* to permit some inefficiency in standards for the smaller projects. Such small projects are not subject to the contingent projects regime and so do not entail full cost–benefit analysis using updated information at the time close to project commencement (below). However, a major reason for having a threshold in the first place was in recognition of the fact that applying a full cost–benefit analysis to every project would involve excessively high transactions costs. Accordingly, from a broader perspective, the standards would still be efficient.
- *Incentives to cost minimise and innovate are maintained*. For projects under the chosen threshold, there are strong incentives for a profit-motivated TNSP to seek the least-cost solution to meet the standard. For projects above the threshold, the public RIT-T process should help identify innovative solutions, and as revenues are then determined for specific projects, profit-motivated TNSPs have strong incentives to cost minimise. For both, the retention of planning responsibilities with TNSPs enables them to capture any economies of scope that come with combined augmentation, replacement and maintenance planning. Grid Australia claimed that this was a significant benefit (sub DR91), though it provided little evidence about the magnitude of those benefits. Moreover, TNSPs may also be better placed to implement 'firm access' requests under the optional firm access

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 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.

(OFA) model (which is also subject to regulatory controls — chapter 19) as they would be able to manage both market based (generator led) and reliability required investments. (The AEMC has suggested that if OFA is adopted, generator led investments will likely reduce the amount of reliability planning undertaken in the NEM (sub. DR89).)

- *The opportunity for windfall gains is minimised*. Large lumpy projects over the threshold, for which timing is critically affected by factors such as forecast demand that is subject to error (Grid Australia, sub. DR91, p. 18) are assessed independently, with updated information prior to commencement. This means that TNSPs are not provided revenues upfront for projects that are delayed or even deferred to the next regulatory cycle. However, limited risks remain for below threshold projects. This could potentially be overcome by 'clawing back' any windfalls gains (or correcting for losses if projects need to be brought forward) (box 16.4) through an efficiency benefit sharing scheme. An efficiency benefit sharing scheme is now permitted by the Rules, but is yet to be developed by the AER (AEMC 2012r, p. v and chapter 5).
- *NEM-wide effects are considered*. NEM-wide effects are incorporated through the NTNDP, the standards themselves and AEMO's role as planner and procurer of last resort. Further, with stronger incentives created by the recent Rule changes, businesses are more likely to seek out cheaper inter-regional options than previously. However, the PC model does not guarantee that the smaller investments made by TNSPs would fully account for NEM-wide effects. In that sense, it is possible that the PC model would provide a more ad hoc set of solutions to network effects than that of a centrally planned model. However, there are also offsetting advantages of relying more on local knowledge and the benefits of the synergies with general operating and maintenance decisions for smaller projects. This suggests that, on balance, the PC model would not result in significant costs associated with its slightly weaker consideration of NEM-wide effects.
- *But there are some additional administration and compliance costs.* The PC model requires AEMO to plan nationally when setting the standards, provide input into the RIT-T process and act as the planner and procurer of last resort. There would also be a number of additional costs in embedding the necessary 'checks' in the system to ensure efficient investments take place and in funding AEMO to undertake its significantly expanded role. These include:
  - the ongoing enhanced development of both annual NTNDPs and NEM-wide cost–benefit probabilistic modelling to set standards by AEMO
  - the additional review of proposed TNSP investments by the AER and AEMO as part of the 'contingent projects' approach to investments over the threshold

- ··· however, removing large projects from the revenue determination process may generate some savings

– the requirements placed on AEMO to discharge its responsibilities as planner of last resort.

Box 16.4 Minimising windfall gains or losses for below threshold projects

Grid Australia (sub. DR91, pp. 18-9) and SP AusNet (sub. DR99, p. 5) suggested that a scheme to 'claw back' allowed revenues provided for projects which did not go ahead (or were deferred) due a divergence of actual demand to that which was forecast at the time of the AER revenue determination would eliminate windfall gains. The same scheme could be used to make up for losses related to additional projects that were brought forward in instances where demand increased.

The approach would be an attempt to determine the windfall gain (or loss) element related to demand changes from that of the efficiency savings made by a profit motivated business (through a re-evaluation of the revenue determination using actual instead of forecast demand). This would be done at the end of the regulatory period with windfall gains returned to the AER (or additional revenues to cover losses approved).

Similar approaches have been used elsewhere, both in Australia and other countries. For example, the Essential Services Commission Victoria has applied an analogous approach to the gas sector where windfall gains were netted out allowance for efficiency savings. Under the arrangements, an 'efficiency carryover mechanism' is used to provide financial rewards (or penalties) for both opex and capex efficiency gains relative to the benchmarks (ESC 2008, p. 570). This is adjusted to take account of difference between forecast and actual work undertaken due to changes in demand (for example, new connections) (ESC 2008, pp. 573-4). The UK Office of the Gas and Electricity Markets also makes use of adjustments based on actual versus forecast demand in its uncertainty mechanisms to aid in determinations of the efficiency incentive rate it provides to network businesses (Ofgem 2012, p. 31).

The Commission understands that with the recent Rule changes (AEMC 2012r, p. v), the AER could pursue such an approach under the range of existing tools used to provide incentives to reduce capital expenditure.

Grid Australia (sub DR91) has also suggested that a model with explicit standards makes reliability planning more transparent and TNSPs more accountable for any breaches in reliability requirements than the central planning model used in Victoria. Such a model avoids concerns over who is liable if an outage occurs. However, in terms of transparency, both approaches are similar if modelling is made public and auditing takes place. As both models are underpinned by probabilistic assessments of costs and benefits, knowing '*why the standard (or* *investment) is what it is*' will be the same and relies on AEMO making public its modelling. Knowing '*what the standard is*' and '*whether the standard is being met*' is informed by public reporting of investment auditing.

Applying the proposed planning framework will also generate benefits for investment and replacement projects not related to reliability. The 'contingent project' approach provides greater incentives for TNSPs to pursue 'market driven' projects, which may get delayed under the existing arrangements. Under incentive regulation alone, networks have the incentive to propose market driven investments and to have the associated revenues included in their revenue allowances, but then defer these projects. This arises as external parties generally have difficulty in assessing whether this deferral was efficient or not (they cannot be judged against specific standards). Under a contingent project approach, no such incentives exist as the network can only access the revenue at the commencement of a project.

Is the PC model robust to changing circumstances?

The regulatory solutions to the problems posed by reliability requirements depend on other regulatory settings and the behaviour of the network businesses. The Commission considers that its model is relatively robust under different regulatory contexts.

However, a major caveat to the above conclusion exists. It is critical that the right governance model be chosen to implement the PC's model. In particular, the benefits of the PC's model would be reduced were the states to appoint their own regional planners to undertake the probabilistic analysis (as recommended by the AEMC for its own model) because:

- the administrative and compliance costs would be high given duplication
- there would be questions about different methodologies (and therefore accountability) and the quality of the analysis
- the consideration of NEM-wide effects would, at best, be clumsy
- there would be concerns that political preferences, which are rarely accurate approximations of true VCRs, and can vary frequently, could be brought to bear on the standards.

Accordingly, the Commission considers that any probabilistic analysis and general planning be NEM-wide and undertaken by one body (preferably AEMO).

Transition costs in implementing the reforms

Moving to the PC model will impose some transition costs on the jurisdictions and electricity market participants. These will relate, in part, to the pace at which reform occurs.

The regulatory determination periods place some natural constraints around the implementation of any reforms to transmission reliability planning. Regulatory periods vary across the NEM, with the next determination period being 1 July 2013 for ElectraNet in South Australia, compared with 1 July 2017 for Powerlink in Queensland.

These arrangements are further complicated by the presence of the latest Standing Council on Energy and Resources (SCER) directed review being conducted by the AEMC (SCER 2013b). This report is not due to be completed until November 2013 and, if agreement is reached at SCER on its recommendations, an implementation plan (but absent any Rule changes) would not be considered until mid-2014.

Both these factors would delay the implementation of any reforms to transmission reliability planning arrangements. Due to these and other concerns over the timeliness of reform within the NEM, the Commission has made a number of recommendations, which would accelerate the reform process (chapter 21). However, even if the decision-making processes were overhauled and accelerated, state and territory governments and the relevant TNSPs would still have an extended period to plan the implementation of the new recommended framework. The proposed reform will not be a disruptive and sudden shock to existing planning arrangements for most jurisdictions, and therefore there should be few transition costs.

In Victoria, the desired transition timetable is more complex than some others. On the one hand, Victoria's reliability framework is already close to that recommended by the Commission and therefore the degree of regulatory change for Victoria is much less than other jurisdictions. On the other hand, Victoria might be reluctant to shift given the tradeoff between the resulting smaller benefits of reform for that State and any transitional costs. Nevertheless, given the long-run benefits, there remain strong grounds for Victoria to move to the Commission's proposed framework, but there is a weaker imperative to fast-track reform in that State. The Commission's proposed timetable for reform in this area is set out in chapter 21.

16.6 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 criterion, and total revenue at risk are unique for each business with rewards and penalties not required to be symmetric. 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.

Following a review of the STPIS for transmission businesses, the AER has made amendments to the scheme. These include an additional network capability component to encourage transmission businesses to 'deliver benefits through increased network capability, availability or reliability through the development of one-off projects that can be delivered through low cost operational and capital expenditure' (AER 2012r, p. 9).

The AER has also decided to include a:

- circuit outage rate parameter as part of the service component to measure the number of unplanned faults on transmission networks
- reporting only parameter to measure the number of times that protection and control equipment fail to operate correctly.

The amendments are intended to strengthen the incentives contained in the STPIS and encourage more efficient use, operation and augmentation of the network.

The AER has suggested that the new measures are lead indicators of possible future reliability issues. If so, such indicators would provide useful information to AEMO in assessing current levels of reliability in the NEM when setting standards.

Transmission businesses appear to have responded positively to the incentives offered under the STPIS (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 as 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 were too high, customers would pay more for reliability improvements than they cost to achieve.

In the context of the PC's reliability and transmission planning model, the STPIS would become an important driver of reliability performance for several reasons.

- Probabilistic planning to set standards is likely to reduce redundancy specifications in at least some parts of the NEM (including reducing the potential for overbuilding), which might increase the risk of more and longer interruptions to supply unless businesses manage their maintenance, operation and response outcomes in an appropriate way.
- 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 future 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 its recent 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.[8] 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.

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

8 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.

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 operating 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.

16.7 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) span a range of measures, 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.

RECOMMENDATION 16.1

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 transmission reliability framework in which reliability settings would be determined by customer preferences (recommendation 14.1).

This framework should replace all jurisdiction-specific transmission reliability settings.

RECOMMENDATION 16.2

A new approach to transmission reliability planning should be adopted. The Australian Energy Market Operator (AEMO) should carry out probabilistic cost–benefit transmission planning for all transmission networks in the National Electricity Market in order to set reliability standards and demand forecasts at each connection point. AEMO should:

- ***use Values of Customer Reliability (as obtained through recommendation 14.2)***
- ***use best practice probabilistic processes in its cost–benefit analysis of efficient standards***
- ***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***
- ***work closely with the relevant distribution companies in determining demand forecasts and cross checking the reliability settings for each connection point***
- ***use its best estimate of peak demand forecasts, having sought input from all relevant stakeholders***
- ***set standards reflecting the probabilistic analysis at the connection point level throughout the National Electricity Market.***

RECOMMENDATION 16.3

The regional transmission network service providers should plan necessary augmentation and replacement investments with reference to the reliability standards set by Australian Energy Market Operator (AEMO) and the National Transmission Network Development Plan. This should have two components.

For augmentation and replacement projects below a threshold value:

- ***the regional transmission network service provider should submit plans and seek funding for investments to meet reliability standards as part of the ex ante revenue determination process with the Australian Energy Regulator (AER), but could, ex post, decide to solve reliability problems in any way it decided was most efficient.***

For augmentation and replacement projects above a threshold value:

- ***the regional transmission network service provider should submit details and seek funding of investments to meet reliability standards as part of the improved Regulatory Investment Test for Transmission process under which the AER would approve the allowable expenditure, having taken advice from AEMO.***

At the next regulatory reset, the actual capital spent on such projects should be included in the transmission business's Regulatory Asset Base, subject to any ex post review if expenditures exceeded the allowable revenues as set out in the approved Regulatory Investment Test for Transmission. If an ex post review identified instances of over-expenditure linked to inefficiently timed capacity increases, inclusion of the over-expenditure in the Regulatory Asset Base should be deferred until such time that the additional capacity would have been net beneficial. For cost overruns, only the efficient investment spend should be included in the Regulatory Asset Base.

RECOMMENDATION 16.4

The Australian Energy Regulator should ensure that, in the Australian Energy Market Operator's role as a transmission standard setter, its public reporting and planning processes are adequate, transparent and meet the National Electricity Objective.

RECOMMENDATION 16.5

The Australian Energy Market Operator (AEMO) 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, AEMO should closely consult with network businesses and seek independent peer review of its technical methods.

RECOMMENDATION 16.6

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, appropriate maintenance and operational standards are being achieved, and intrinsic network reliability is maintained.

RECOMMENDATION 16.7

The Australian Energy Market Operator (AEMO) 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 AEMO 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.

RECOMMENDATION 16.8

The Australian Energy Regulator should review the Service Target Performance Incentive Scheme for Transmission to ensure the incentives and targets are consistent with the recommended National Electricity Market-wide reliability framework.

RECOMMENDATION 16.9

Transmission businesses not already using dynamic capacity ratings on all critical equipment should transition to this approach.

16.8 Contestability in new connections and other separable transmission investments

Currently, Victoria is the only jurisdiction that has introduced contestability into some augmentations of the transmission network — those of separable investments likely to cost over $10 million.[9] (The future introduction of the OFA arrangements[10] discussed in chapter 19 may introduce an element of competition between TNSPs that could compete to provide firm access to existing generators.) Contestability in the provision of separable investments has been seen as a means to reduce market power and overcome information asymmetries:

> Transmission services need to be procured efficiently given their high costs. Where possible, this should be achieved through competitive tendering of the construction and ownership of major network investments. Effective competition has the capacity to reduce market power and overcome information asymmetry problems. (AEMO, sub. DR100, p. 6)

Most concerns expressed relating to TNSP market power and information asymmetries have been raised in the context of new connections — a subset of

9 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. 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 capital expenditure is therefore not incorporated into SP AusNet's RAB at the start of the next regulatory period.

10 OFA arrangements are targeted at providing firm access for generators to downstream markets. The arrangements, through proposed price controls, also include regulation that seeks to limit the potential for TNSPs to exploit any market power over incumbent generators when providing firm access — chapter 19. Broader issues of market power and transmission businesses are being examined by the AEMC's Transmission Framework's Review (AEMC 2011f and 2012j).

separable investments. This section examines the case for introducing contestability into new connections (with possible extension to other types separable projects, such as interconnector investments, if benefits are proven) and recommends a model for this to occur throughout the NEM.

New connections to the transmission network

New generator connections to the network are generally regarded as additions 'outside' of the shared network. However, they also often require upgrades to the shared network itself.

Concerns have been raised about the possibility for TNSPs to exploit their market position in dealings with the connection of new generators to the NEM. For example, the Clean Energy Council argued that:

> … some areas where new entrant generation interacts with networks is done so without sufficient regulation. The CEC [Clean Energy Council] believes that in almost all of these cases networks behave in the exact ways that the Commission describes that an unregulated monopoly would behave. (sub. DR97, p. 4)

And that:

> … the current negotiating frameworks are failing to produce efficient outcomes as a result of market power held by TNSPs. New generators are unable to connect efficiently and, ultimately the increased cost is distributed to consumers. (sub. DR97, p. 9)

Monopoly behaviour can manifest in delays, lack of information provision and passing on (greater than efficient) costs to new generators. Further, where new connections also require upgrades in other areas of the shared network to deal with issues such as higher loads being transferred, it is difficult for new generators to objectively assess whether or not they are paying for just the required upgrades, or whether additional costs are also being passed on (AEMO, sub. DR100, p. 9).

The Victorian Government has long held concerns in relation to this, stating that:

> Under current connection arrangements there are insufficient regulatory controls on TNSPs to ensure that connection applicants receive 'fair and reasonable' treatment. The outcome of any given connection process is highly dependent on the willingness of the TNSP to proactively engage, and on the TNSPs providing the required information to the applicant to enable them to negotiate on the basis of full information. Unfortunately, this fair treatment is often not forthcoming. (DPI 2012b, attachment p. 13)

Outside Victoria, access arrangements under the Rules are delivered as negotiated transmission services. However, as put by the Clean Energy Council, an efficient outcome from this arrangement requires the connecting party to have countervailing market power (sub. 97, p. 7).

Concerns have also been raised over the Victorian arrangements. In regard to AEMO's role in Victoria as a 'procurer', some participants have expressed concerns about the costs involved for businesses submitting tenders, for the incumbent transmission business, for the generator, and for AEMO when carrying out the tender process. Some participants (for example, the National Generators Forum, sub. DR93) have also claimed that the process in Victoria creates requirements to negotiate many contracts with different parties, creating significant additional transaction costs. Similar sentiments were expressed by AGL Energy (trans., p. 223) which saw the involvement of AEMO in Victoria as adding few benefits but adding delays, cost and complexity. While remaining concerned about the market power of TNSPs, AGL Energy maintained that when seeking new connections they would prefer to deal directly with the relevant TNSP.

Proposed reforms

As part of the Transmission Frameworks Review, the AEMC is considering reforms to the connections process. In order to deal with the issues of monopoly behaviour identified above, the AEMC's second interim report (AEMC 2012j, p. 84) recommended reforms designed to strengthen the negotiating framework. These include:

- requiring TNSPs to publish a standard connection contract, and 'design standards and philosophies' for analogous distribution connections
- requiring TNSPs to provide connection applicants with detailed cost, assumption and calculation information and evidence
- a power for the AER to develop and enforce guidelines on specific information that TNSPs must provide to applicants.

The AEMC also sought to provide connection applicants with a greater role in the tendering process for connections (a process which would be run by the TNSP), by requiring TNSPs to provide applicants with:

- all contractors' responses to the tender
- a detailed business case for the choice of contractor, including demonstrating that the TNSP has considered the applicant's preferences in selecting the winning contractor.

Separately to *connections*, the AEMC also sought to clarify the rules to allow a connecting party to tender for an *extension*, in whole or part (the AEMC's delineation between connections and extensions is depicted in figure 16.3). They noted that TNSPs could participate in the tender, but that the applicant can request that the TNSP provide the extension as a negotiated (that is, regulated) transmission service. Finally, the AEMC considered that, due to competition concerns, controlling ownership of both generation and shared transmission assets should not be allowed.

The AEMC's proposed reforms essentially followed the principle that 'competition for services will lead to the most efficient outcome, where it can be effectively implemented' (AEMC 2012j, p. 87). In implementing this principle, the AEMC has proposed contestability for extensions, but have stopped short of this in the case of connections, relying on increased transparency to curtail monopoly power.

The AEMC argued that connections should remain the responsibility of TNSPs because:

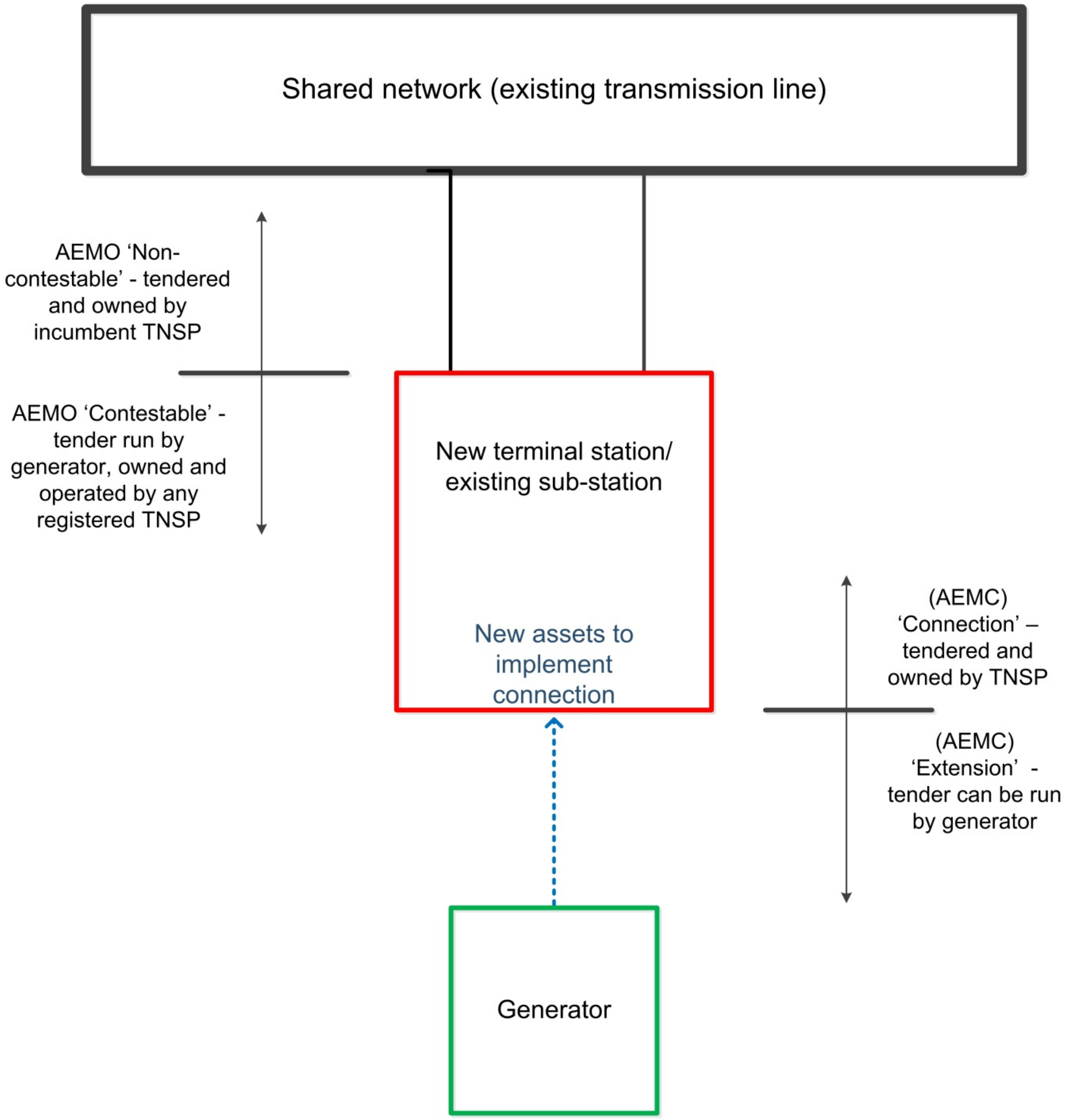
> … they are responsible for security and reliability of the shared network, which could be impacted by the design and construction of the connection. … There is an inherent tension between the desire for a connecting party to minimise its costs of connecting to the transmission system and the advantage to a TNSP of having the most reliable and long-lasting transmission assets possible. (AEMC 2012j, pp. 86-7)

Through the course of the Transmission Frameworks Review, AEMO put forward an alternative contestability framework (detailed below, and in AEMO 2013d). Essentially, AEMO agreed with the objectives of introducing competition for services where practical, and maintaining the security and stability of the network. However, AEMO differed from the AEMC's model in two key respects:

- defining the boundary between those services, which could be subject to contestability and those that could not (depicted in figure 16.3). While the AEMC considered that contestability should only apply up to the 'substation fence', AEMO argued it could apply up to the interface with an existing transmission line
- the means for ensuring system security. Rather than simply retaining responsibility with the TNSP, AEMO argued that they could stipulate technical requirements at the connection to ensure system security. The construction of new assets, by the incumbent or any other successful tenderer, would be required to meet these specifications.

While the difference in boundary definition could seem minor, the Commission received confidential information that typically the sub-station component alone represents more than half of the capital cost required for a new connection, and could be as large as 80 per cent for some connections. This suggests that any gains from contestability will also be proportionally larger if they include sub-station works.

Figure 16.3 **The boundary of a contestable connection**



Data sources: Based on AEMC (2012j); AEMO (2013d).

While the AEMC's approach to connections covers several other aspects of the process (such as clarifying the National Electricity Rules, and transitioning extensions to shared network when other parties connect), the Commission agrees with the AEMC, in that reform should focus on introducing competition, where practical. The Commission's suggested approach for connections reform is detailed below.

Introducing contestability into new connections

A new 'specifications' based contestability model for the NEM, based on the broader contestability framework proposed by AEMO (sub. DR100, pp. 9-10), could be adopted to introduce contestability into new connections (and possibly eventually to other separable projects should net benefits be proven). The approach overcomes the criticism to the current Victorian arrangements.

- Applications for connection to the network are made to AEMO who determines the required specification to upgrade and augment existing network infrastructure to accommodate the new connection. Unbiased information about the range of shared network upgrades that would be required to accommodate the connection is then provided by AEMO in an open and transparent manner. While this would require that TNSPs provide information to AEMO, it would be appropriate for a central body, with no financial interest at stake from any particular interpretation of the information, to provide this information to the market. Indeed, provision of this information meshes well with AEMO's other functions. This was noted by the Clean Energy Council which suggested '… as AEMO has the ultimate responsibility for system security and constraint management, there should not be any barriers to [it] having access to all the necessary information'(Clean Energy Council 2013, p. 4).[11] This process would go some way to alleviating the information asymmetry held by TNSPs over new generators and ensure that the safe operating state of the network will be maintained.[12]
- Generators are then free to tender the separable component of the connection, subject to the published specifications to interested parties — including the incumbent TNSP. This aspect allows for third parties to compete for the building and ownership of the connection assets. Unlike the current practice in Victoria, AEMO would not be involved in any commercial negotiations. This will help to delineate lines of responsibility between the generator, the successful tenderer and AEMO and thereby improve accountability if an issue were to arise.

[11] To the extent that the acquisition, compilation, analysis and publication of the additional information would require additional staff and resources for AEMO, these costs should be recovered from connection applicants (who benefit from the information), rather than 'spread' as network charges.

[12] There may be elements deep within the shared network where the information asymmetry in favour of the TNSP is effectively insurmountable due to, for example, complex network interactions or specific local knowledge (of topology or local regulation). Improving transparency by both AEMO and the TNSP providing information to the applicant would go some way to 'shedding light' on this work but, as noted below, there are some areas where it is best that the TNSP conduct the work.

- The AER would oversee the process through the development and enforcement of a national negotiating framework (including guidelines for the provision of information by TNSPs), as envisaged by the AEMC (2012j, p. 86). The AER would also continue its present role of selecting a commercial arbitrator from the options put forward by the parties (if called on by the parties to do so).

AEMO (2013d) raises the possibility of cross-ownership of the transmission assets (including the substation) by other registered transmission operators (not the local incumbent). In the case of sub-stations, the degree of complexity involved, and the potential effects on the broader network from deficiencies with the operation of a sub-station, suggest that cross-ownership is unlikely to have substantial net benefits. Therefore, the Commission proposes that the connection assets related to the sub-station could be constructed under a 'build and transfer' arrangements where asset ownership was transferred to the incumbent TNSP, if it is in the owners commercial interest to do so.[13] Ultimately, the details of such a transfer would be a commercial decision for the parties involved. If the incumbent TNSP won the tender, the generator would avoid the additional transaction costs of transferring ownership at the completion of works. This would represent one inbuilt advantage for the incumbent, and a consideration for the generator in selecting the winning bid. This allows the generator, a commercially motivated party (in a workably competitive market), to select the model it believes delivers the best value to it.

In relation to 'extensions' (works between the sub-station and the generator itself), the Commission agrees with the AEMC (2012j, pp. 100-4) that provided a third party or the generator is either a licenced TNSP, or obtains an exemption from the AER, it could own the extension. Such exemptions should be subject to conditions including provision for third party access. Over time, some extensions can be accessed by other parties, or could be reclassified in such a way that they effectively become part of the shared network. The process for transitioning extensions into the shared network is being considered in some detail by the AEMC (2012j, pp. 101-3).

The competitive disciplines placed on TNSPs should overcome a number of the concerns raised, such as delays, over pricing and possible risk transfers from TNSPs to generators that can arise in transactions with monopolists.

Further, using AEMO to set the specifications for the connection projects prevents the possibility for delay or opportunities to frustrate the process if it were left to the incumbent TNSP to complete. It will also ensure generators can be confident that they are not paying for upgrades to shared network infrastructure that are not related

[13] Once the asset ownership has been transferred to the TNSP, as a 'negotiated transmission service', it would not be counted as part of the RAB (National Electricity Rules, clause 6A.6.1(a)).

to their connection. Indeed some generators have already expressed support for AEMO's model, and argued that it would 'make significant enhancements to the efficiency of new connections' (Clean Energy Council 2013, p. 5).

Implementation of this approach, however, could be hampered by other regulatory barriers that restrict competition. In their submission to the AEMC's *Transmission Frameworks Review* (2011f and 2012j) Transmission Operations Australia raised concerns over barriers created by licensing arrangements:

> There are competition barriers in jurisdictions such as NSW and Queensland. However, these competition barriers are not due to the inherent nature of the electricity transmission market but rather due to imposed legislative and regulatory barriers. For example, in NSW TransGrid is a legislated monopoly and in Queensland the process for obtaining a transmission license is not transparent. (TOA 2012, p. 3)[14]

Accordingly, in order to implement this new approach, all jurisdictions in the NEM would have to ensure that their licensing regimes (and other regulatory imposts such as environmental and planning approval) are transparent and do not contain any unnecessary barriers to the competitive provision of the transmission augmentations needed for new connections.[15]

Grid Australia has also raised concerns over the ability of AEMO to determine connection specifications that ensure system security without specifying the details of the actual configuration of the connection assets (Grid Australia, pers. comm., 27 February 2013). If the detailed configuration is specified, Grid Australia argued that all that will be tendered is the procurement and construction component of the connection, much as a TNSP would do under the current arrangements. This would limit the benefits from contestability, albeit the benefits arising from having the generator undertake the tender would remain. However, in an analogous augmentation to the network, AEMO has shown that it can indeed tender based on specifications that do not extend to being prescriptive over the configuration of

[14] In a submission to the AEMC, TransGrid (2012) obtained legal advice suggesting that 'any company' can build own and operate extensions to the transmission network. However, in order to obtain compulsory acquisition powers (to acquire easements over land), a company must apply to the relevant New South Wales Minister for an order under the *Electricity Supply Act 1995* (NSW). To date, one company (Directlink) has been granted such an order (TransGrid 2012, attachment, p. 2).

[15] In considering the presence of entry barriers for generator 'extensions', the AEMC (2012j) examined the state-based licensing requirements and land acquisition powers across the NEM. It concluded that South Australia, where 'third parties can readily obtain transmission licenses and own and operate extensions' (AEMC 2012j, p. 143), had the most competition for the provision of extensions. A full examination of barriers to entry would also need to consider if broader government approvals (such as environment and planning) afford any competitive advantages to incumbents.

assets required — in its network support and control ancillary services tender of 2012.

RECOMMENDATION 16.10

The Australian Energy Market Operator (AEMO) should oversee the technical details of connection of new generators to the National Electricity Market to allow for contestability. AEMO should:

- ***on receipt of an application for connection from a generator determine, in consultation with the relevant transmission business, the details of the augmentation and upgrades to shared network infrastructure that would be required to implement the connection, as well as the detailed specifications that ensure that the safe operating state of the network is maintained. This would complement information provided by the transmission business. The transmission business would have the opportunity to review and provide commentary on AEMO's proposed specifications but AEMO would make the final decision on the required specifications***
- ***provide the specifications to enable the generator to seek tenders to build the connection assets.***

The Australian Energy Regulator should provide guidelines on the provision of information from transmission businesses to new connection applicants.

This framework should replace the existing arrangements in Victoria immediately and be implemented elsewhere in the National Electricity Market once Victorian arrangements are finalised and any regulatory barriers have been overcome.

17 The Regulatory Investment Test for Transmission

Key points

- The Regulatory Investment Test for Transmission (RIT-T) is a cost-benefit test that is performed before major new transmission projects are commenced. It does not dictate revenue allowed for particular projects. While a useful tool, it has some shortcomings.
- There is inevitably scope for those conducting any cost–benefit test to influence the outcome. At present, there is no independent approval of the RIT-T. Therefore, the party that performs the test can have financial incentives to achieve a particular outcome.
  - There is a need for increased involvement from independent parties.
- In line with its recommendations for transmission planning, the Commission recommends an enhanced process and new role for the RIT-T.
  - All projects (both augmentations and replacements) above a threshold value would be subject to a revised RIT-T, and a contingent project based determination for the revenue for that project. This threshold would be indexed over time to maintain its real value.
  - The RIT-T documentation would become the business's revenue proposal.
  - The AER (Australian Energy Regulator) would assess the merits of the RIT-T (as well as the process).
  - Once approved by the AER, revenue for the allowed sum could be recovered through network charges. At the next regulatory determination, the actual capital spent would be rolled into the regulatory asset base.
- Taking on this new role necessitates changes to the RIT-T process.
  - Transmission businesses would remain responsible for conducting the test, with AEMO (Australian Energy Market Operator) conducting a parallel analysis.
  - The AER would effectively approve the RIT-T through the 'contingent projects' process. AEMO's advice would be presumed to apply, unless the transmission business could provide convincing alternative evidence.
  - The RIT-T would become a full cost-benefit analysis, including updating probabilistic reliability standards as part of the overall benefit calculations.
- The current test only allows consideration of costs and benefits that accrue to those who produce, consume or transport electricity. There are both theoretical and pragmatic reasons for not expanding this to include costs and benefits to other parties.

Incentive regulation of Transmission Network Service Providers (TNSPs) (chapter 5), the reliability standards with which they must comply and the broader transmission planning process (chapter 16) are the major drivers of TNSP investment decisions. However, there is another regulatory process that can influence the choice of transmission projects — the Regulatory Investment Test for Transmission (RIT-T), which is a cost–benefit test applied to specific major transmission projects.

In concert with transmission planning, the goal of the RIT-T 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 the RIT-T currently makes towards achieving efficient levels of transmission and interconnector investment in the National Electricity Market (NEM).

Importantly, a revised transmission planning framework (chapter 16) brings with it a new role for the RIT-T.

17.1 The current framework

The RIT-T is a cost–benefit process that is done before all major new transmission projects, including interconnectors, are undertaken.[1] 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.[2] In doing so, it includes several categories of costs and benefits (box 17.1).

1` Currently, a ‘major project’ is one in which any of the options considered would cost more than $5 million. For projects between $5 and $38 million, a ‘streamlined’ version of the RIT-T is conducted with lower consultation requirements. Projects above $38 million require a standard RIT-T. The previous threshold of $35 million was recently reviewed by the AER in 2012, and updated to $38 million to reflect changes in input costs (AER 2012u).

2 The AER (2010e) only stipulate that a ‘commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector’ be used to calculate the net present value. Grid Australia’s (2011a) RIT-T cost–benefit analysis handbook suggests a 10 per cent rate should be used, unless there are ‘compelling reasons to adopt a different rate’.

Box 17.1 **The costs and benefits in a RIT-T under the current system**

For any proposed new investment, the party performing the RIT-T compiles a list of options. These options can be network options, or alternatives such as demand management or a new generator. At this stage of the process, interested parties can raise alternatives that must be considered, or a rationale given for their exclusion.

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
- changes in voluntary load curtailment (users reducing 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 scenario will occur. The project with the highest, probability-weighted, net present value is chosen by the TNSP for development (if the project is 'reliability driven' this value may be negative).Throughout the RIT-T process, 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 that the regulator 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).

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.) It is important to recognise that the RIT-T is just the most recent form of regulatory test applied to transmission, and previous versions of the test did consider some issues of distribution (box 17.2).

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 itself does not determine the revenue allocated for a particular project. Instead, it 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 deliver an efficiently 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 selected the available option with the highest net benefits, given the deterministic constraints, but it cannot alter the inefficiency of those constraints.

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, such as suggested alternative solutions, for a particular investment to come forward.[3] For example, a generator announcing that it was planning to commission a new plant in an area could make a network augmentation unnecessary.

3 The TNSP is required to make the project specification report available to all registered participants (in the NEM), AEMO, and ‘interested parties’ (AER 2010g). ‘Interested parties’ is broadly defined to include those with an interest in network planning, or with the potential to suffer an adverse market impact from the proposed transmission investment. Both AEMO and the AER play a role in determining whether a party qualifies as an ‘interested party’.

Box 17.2 **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. Some have argued that, in the name of regulatory certainty the recent introduction of the RIT-T might militate against reforms to it 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–New South Wales interconnector, the National Energy Market Management Company Limited found that the customer benefits test was 'highly volatile' (ACCC 1999).[4]

The first regulatory test was introduced in 1999 by the Australian Competition and Consumer Commission 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 the lowest overall cost, and the introduction of new consultation requirements. The RIT-T is also more prescriptive in how to calculate costs and benefits (AER 2010f, p. 2).

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.

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 attempt to produce the perfect estimate of the net benefit of any particular option.

4 Hypothetically a (short-term) customer benefits test could approve an investment that resulted in a benefit, of say $1 million to electricity consumers, but imposed a cost on particular generators (which 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 focusing on the *long-term* interests of consumers, would be unlikely to be met for such an investment.)

17.2 Issues with the current RIT-T

As identified in chapter 16 (box 16.2), and above, there are several issues with the broad functioning of the RIT-T in its current form. Principally, these relate to the responsibility for the conduct and 'approval' of the test, the incentives provided (particularly in relation to projects identified as necessary on reliability grounds), and the consequences arising from the performance and outcome of the test.

Responsibility for performing and 'approving' the RIT-T

Despite its name, the RIT-T is not performed or 'marked' by a regulator. Instead, it is undertaken by the entity with responsibility for transmission planning in each jurisdiction.

Consequently, in New South Wales, South Australia, Tasmania and Queensland, the relevant transmission business performs the test, with the limited oversight provided by the Australian Energy Regulator (AER) focused only on matters of process, rather than assessing (or approving) the TNSPs' analysis. The TNSP is also responsible for arranging the construction of a new asset if the RIT-T finds it to be the available option with the highest net benefits. As such, there is no independent assessment of the merits of the RIT-T.[5] Some participants argued that there were sufficient controls, and oversight by outside parties, to ensure that the RIT-T would be applied appropriately by TNSPs:

> … the RIT-T is a highly prescribed test that is conducted with oversight by interested stakeholders and the AER. This oversight is also strengthened through the AEMC's [Economic Rule Change] proposals. While the current formulation of the test is still relatively new, there is no reason to suggest that this test will not be applied as prescribed and in good faith. (Grid Australia, sub. DR91, p. 33)

In Victoria, the RIT-T is performed by the Australian Energy Market Operator (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. Small projects, or projects that are unable to be separated from the network, are provided by the incumbent TNSP (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, operate and own the augmentation. While TNSPs in other jurisdictions, and AEMO in Victoria, all conduct a RIT-T, outcomes in Victoria can be markedly different, as:

5 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.

- AEMO also conducts a (broader) cost–benefit analysis in the course of its own planning process
- AEMO applies probabilistic reliability standards, meaning that projects must pass a cost–benefit analysis, in contrast to the existing special treatment for reliability under the RIT-T (below), and
- having an independent party (other than the TNSP) responsible for performing a cost–benefit analysis and the RIT-T (including consultation processes), and effectively approving its outcome, changes the role and nature of the RIT-T.

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. 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 scenarios[6]
- 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). Notably, this can include the relative risks, particularly to the stability of the network, of various options.

Under the current framework, TNSPs undertaking the analysis can have a financial incentive to favour a particular outcome. The presence of financial rewards or penalties in the incentive regulation regime (chapter 5), as well as additional objectives brought to bear on government-owned TNSPs (chapter 7) could drive a TNSP to favour investment options that may not necessarily be optimal from the perspective of an efficiently-operated NEM. For example, in certain circumstances, a transmission business 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 intra-state option over an interstate option. Such incentives may, consciously or unconsciously, reduce the impartiality of consideration of all options and thus diminish the capacity of the RIT-T to effectively perform its intended role.

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6 At broad level, AEMO already effectively sets the scenarios as the TNSPs adopt those set out in AEMO’s National Transmission Network Development Plan.

On the other hand, it could be argued 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 transmission business, 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. Further, the detailed local knowledge and experience possessed by TNSPs could mean that they are aware of particular advantages and disadvantages of options that may not appear obvious to a third party — this could include familiarity with local planning requirements, local geography as it effects construction options and costs, and pre-existing relationships with both regulators and prospective tenderers.

Nonetheless, the conflict of interest arising from those with a financial interest both conducting the test and approving the outcome, whether real or perceived, remains. Thus, in the Commission's opinion, some improvements to the transparency and oversight of the RIT-T, and the disciplines on TNSPs in conducting the test, are warranted.

Information asymmetries

In their roles as network service providers (and planners), TNSPs possess detailed information of their own network and the power that flows through it. While the current RIT-T (as well as TNSP annual planning reports) brings some level of transparency, it relies on outside parties to challenge the TNSP's analysis, or to propose alternatives the TNSP will later analyse.

Most outside parties are unlikely to possess the detailed information that the TNSP has, or to have the broad understanding of the network (many parties will only have knowledge of one facet of the network problem and potential solutions depending on their expertise, such as generators or demand aggregators).

Given this asymmetry, the third party discipline created by publishing the results is muted, and limited in its effectiveness.

Consequences from the RIT-T

As discussed above (and in box 17.1), there is no formal regulatory approval of the RIT-T. The outcome is selected by the TNSP. The only role for the regulator is purely administrative — ensuring that TNSPs have followed required processes — rather than any substantive assessment of the merits of the proposed outcome.

At most, the AER can instruct that the RIT-T is redone, with the procedural elements (for example, minimum time allowed for consultation) corrected. The AER noted that it felt these powers were 'limited' and difficult to exercise:

> As the RIT-T and the associated Electricity Rules are not civil penalty provisions, the only formal remedy available to the AER to address a breach of the RIT-T is court action seeking an order for the business to redo the RIT-T. This is both resource and time intensive. (sub. DR92, p. 9)

Indeed, some participants (such as the Total Environment Centre, sub. DR50) perceive the AER's current role as little more than 'rubber-stamping the results of processes conducted essentially by the proponents for their own benefit' (p. 6).

Further, as noted above, the RIT-T does not determine the allowed revenue for a particular project (with revenue instead being set through the broader incentive regulation process).

As such, the RIT-T itself has little (direct) consequence.

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. In contrast to this, interconnectors are not subject to reliability standards, and must be justified on market benefit grounds (that is, they must have a positive NPV). As there is a lower (and more simply expressed) hurdle for reliability standards, intra-regional transmission projects could be given priority over interconnectors, despite the lesser relative merits of these if considered through the lens of the NEM as a whole.

One option for reform would be to assign reliability standards to interconnectors so that all interconnectors and intra-regional transmission received equal treatment under the RIT-T. The Australian Energy Market Commission (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 19), replacing the need for setting reliability standards for interconnectors as a stand-alone option.[7]

[7] 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 19), which would effectively perform the same role as a reliability standard.

Further, to the extent that existing reliability standards are inefficient, 'levelling the playing field' by applying similar standards to interconnectors would simply spread any inefficiencies.

In chapter 16, the Commission recommended moving to probabilistically-set reliability standards for all transmission projects. In the context of the RIT-T process, a move to probabilistically-set standards would remove 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 New South Wales, 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 the similar model proposed for NEM-wide application by the AEMC (appendix F), derived value of customer reliability estimates are used in setting the hybrid standards. As such, projects should, in theory, pass a cost–benefit test (chapter 16). However, changes occurring since the hybrid standard was set, and the coarse nature of the six reliability standard categories, may result in the deterministically-expressed standard not being closely aligned with economic benefits.

Accordingly, removing reliability as a separately identified need in the RIT-T requires, at least, a move to hybrid planning (where standards are underpinned by probabilistic cost–benefit analysis). However, using an up-to-date probabilistic analysis for each RIT-T would provide an outcome more aligned with economic benefits. This is considered further in section 17.3.

17.3 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).

It is also flawed, with the entity responsible (the TNSP) for performing the test also 'approving' the result, and the test itself having little effect to counter-balance underlying incentives on the TNSP. The information asymmetries facing outside parties also hinders their effectiveness in challenging any of the TNSP's propositions. The test itself favours projects justified on deterministic reliability grounds (potentially to the detriment of options involving augmentation to interconnectors). Finally, there are few consequences for TNSPs for conducting inadequate RIT-Ts.

In chapter 16, the Commission recommended a new transmission planning system that incorporates an approval process for large investments based on the current 'contingent projects' model. The RIT-T performs a markedly different role in this new system and, as such, it is important to address the identified flaws inherent in the current RIT-T.

Responsibility for performing the test

Under the Commission's model, the responsibility for performing the RIT-T will remain with the TNSPs in their role as planners for each jurisdiction.[8] This would allow TNSPs to benefit from economies of scope as they can plan on a basis that considers augmentation, replacement and maintenance as part of a holistic process.

For projects above a certain threshold (see below), the AER would approve revenue allowances for individual projects. This process would operate in a manner based on the current 'contingent projects' process. That is, the AER would, in effect, approve the RIT-T through a revenue allowance.

Further, AEMO would essentially 'shadow' the RIT-Ts for large projects, conducting analyses of its own. Based on these analyses, AEMO would provide advice to the AER relating to technical aspects of individual projects such as their timing, choice and costs. In its position as national planner (with responsibility for the National Transmission Network Development Plan and as planner of last resort), AEMO would be well placed to comment on any NEM-wide effects or

8 The Commission considers that Victoria should also transition to the NEM-wide system (chapter 16). Accordingly, SP AusNet would eventually take over responsibility for the RIT-T/contingent projects process.

options. This would also allow it to comment on any flow-on effects from a given investment that may reduce the need for other investments elsewhere in the jurisdiction in question, or the NEM as a whole. Such advice could help to ensure that the AER only approves the net, incremental, investment cost, limiting the opportunities for TNSPs to selectively 'game' the RIT-T by putting projects forward in a particular order, or a particular combination, avoiding the potential for 'cost shuffling', as identified by the AER:

> But the more there is the opportunity for pass-through of costs or recognition of change of circumstances such that, "Things have changed, we actually need more money" the more the prospect then that the business can simply label part of the ex ante allowance as being needed for this activity and the demand is now growing in that area. That then frees up capital in other areas for underspends in other areas. There's all sorts of costs shuffling that can go on. (trans., p. 129)

Importantly, AEMO's advice would have presumptive force with the AER (becoming a form of benchmark). That is, it is presumed that the AER would accept AEMO's advice, unless the TNSP could provide sufficient, convincing, evidence or arguments to refute it. This could arise in a number of circumstances, for example, where the TNSP's investment choice has been informed by its detailed local knowledge and experience, or the TNSP may be pursuing more innovative solutions due to the financial incentives it faces. In suggesting a similar model to the Commission's, Grid Australia emphasised the importance of the ability to refute AEMO's advice in certain circumstances:[9]

> … TNSPs have a much better understanding of their networks, and service performance obligations rest with them. Given these facts it is essential that the option to vary from the recommendations of AEMO remain with TNSPs, where there is strong evidence that AEMO has not chosen the most efficient option and where there is a critical need. (sub. DR91, p. 32)

Giving AEMO's analysis presumptive force encourages appropriate consideration of NEM-wide effects and works to counter-balance some of the underlying incentives faced by TNSPs (which may lead to less than a fully efficient NEM-wide solution). As the Commission has recommended that AEMO be subject to additional reporting requirements in using probabilistic methods to set reliability standards (chapter 16), requiring AEMO to publish their analysis of a major project could also enhance the ability of other outside parties to analyse TNSPs' investment decisions, reducing the extent of information asymmetries.[10]

[9] In Grid Australia's 'enhanced AEMC model' (sub. DR91) the RIT-T would also be conducted by the transmission business 'with scrutiny by AEMO and oversight of the AER' (p. 12).

[10] Theoretically, a third party could use published information to run the probabilistic model used by AEMO to set reliability standards. This would highlight some of the assumptions made by TNSPs in concluding that a particular investment was needed, and that it had a net benefit.

Consequences from the revised RIT-T

As noted above, for projects above a threshold value, the RIT-T would become the first stage in a process based on the current 'contingent projects' model. In such instances, the RIT-T documentation would form the basis of the revenue determination for each project — adding consequences to the RIT-T by tying it to (a component of) the TNSP's allowed revenue. The TNSP would nominate large projects (or a set of circumstances that could give rise to large projects, in a manner similar to the trigger mechanism for contingent projects) in its revenue proposal. These would then be subject to the RIT-T process described below. Additionally, any projects previously identified as 'small', which as the time to invest approaches appear likely to become 'large' for unforseen reasons, would then become subject to the RIT-T. In such cases the AER's revenue determination for the project should take account of the funds already allocated to the project at the time of the regulatory reset, and only allow the incremental increase in funds, not the entire project cost (to guard against double counting of projects).

This process also allows the AER to substantively examine the project selected under the RIT-T. As with a 'full' revenue determination, the AER could investigate a range of issues including the need for, and costs of, a given project and the merits of any alternatives. However, as with a 'full' revenue determination, the AER's role would be to approve the sum of money that the efficient option is expected to cost, *not* to mandate that the identified efficient option is actually built. As with general revenue determinations (chapter 5), if the TNSP were able to complete the project, or meet the identified need, at a lower overall cost (including both capital and operating costs), then it would be able to keep a proportion of the gains.

Once projects were approved through this process, TNSPs could recover the allowed sum through network charges. At the next regulatory determination, the actual project cost (less any depreciation) would be rolled into the TNSP's regulatory asset base, and the RIT-T would be used as the basis for any ex post review process if expenditures exceeded the approved amount.

In short, the RIT-T will become more 'regulatory' and more of a test. While the TNSP still conducts the test and selects the investment option, in financial terms, the AER approves both the merit and process of the test, supported by additional input from AEMO.

RECOMMENDATION 17.1

The Regulatory Investment Test for Transmission process should be revised. The new test should continue to be performed by transmission businesses, but:

- ***be accompanied by parallel independent analysis from the Australian Energy Market Operator. This analysis should be published, and provided as advice to the Australian Energy Regulator (AER). The advice should have presumptive force in the AER's deliberations***
- ***be used by the AER as the basis for a revenue determination for the individual project in question, in a manner similar to the current 'contingent projects' process. The AER should assess and approve both the merit and process of the analysis.***

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, past experience (and initial evaluation) had established that 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 an overall, forward looking estimate included in 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 an alternative, to avoid having to go through the RIT-T process.

In the context of the Commission's recommended approach to transmission planning (chapter 16), the application of the revised RIT-T brings not just transparency, but for large projects is also tied to revenue allowances with focused project-by-project scrutiny. In this environment, there could be greater incentive for a TNSP to simply categorise a project as a replacement at the time of the regulatory determination (and thus not consider conducting potentially scale-efficient augmentations at the same time) to avoid more focused scrutiny of the project, and rely on its inclusion in the (broader) general revenue determination. Further, the level of consultation and scrutiny applied to a project should depend on its significance (in terms of dollars spent, as well as impact on the network), rather than any classification as a replacement for existing investment, or entirely new investment.

Therefore, in contrast to the current contingent project process, the Commission's model is 'triggered' not when some uncertain event occurs, but rather simply by a project costing more than a threshold value (below). As with the current RIT-T threshold, this would also apply when one possible option to address an identified need exceeded the threshold. This means that *all* projects — both augmentation and replacement projects — above the threshold would subject to the revised RIT-T.

One potential concern from expanding the application of the RIT-T to include replacement projects is an associated increase in compliance costs. Indeed, the AEMC submitted that in developing the Regulatory Investment Test for Distribution, it considered including replacement projects but found that doing so 'would impose a disproportionate regulatory burden on DNSPs [distribution businesses] and it would appear similar reasoning also applies to transmission investments' (sub. DR89, p. 9). However, the 'lumpy' nature of transmission investments (as distinct from distribution investments) suggests that relatively few projects will involve large sums of money (and therefore significant impacts on market participants). As such, a proportionate level of regulatory burden can be applied, providing that an appropriate threshold for application of the test is chosen.

RECOMMENDATION 17.2

The revised Regulatory Investment Test for Transmission should apply to all large projects, subject to a uniform threshold value, whether augmentation, replacement or a combination of both.

A threshold for the test

The current RIT-T threshold

The RIT-T currently only applies to network augmentations (notably not replacements) where the cost of any option considered is over $5 million. Further, where the preferred option does not cost more than $38 million, the planner applying the RIT-T can be exempted from parts of the consultation process (AER 2012j, p. 6), effectively conducting a 'streamlined' version of the RIT-T. The $5 million threshold for the RIT-T appears to be a low value, particularly as it applies to the highest cost option considered. However, a low threshold helps minimise the risk of a network business 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 threshold for the current test is not unreasonable. However, under the Rules, the threshold is to be reviewed periodically by the AER. The first review was completed in November 2012. The review (AER 2012u) concluded that the $5 million threshold should be maintained, but that the consultation threshold of $35 million be increased to $38 million, due to a roughly 10 per cent increase in capital input costs for transmission businesses.

A threshold for the revised RIT-T

The revised RIT-T process described above sets up individual revenue determinations for specific projects. There are a number of benefits in doing this as it:

- removes a financial incentive to TNSPs to delay important investments. Such delays may put at risk the reliability of the transmission network (given difficulties in observing latent levels of reliability). Under the revised RIT-T process, there are no incentives for delay as TNSPs cannot access revenues for projects until approved through a RIT-T process
- minimises the possibility of windfall gains (or losses) as allowed revenues are less reliant on extended demand forecasts, which have significant uncertainties attached
- provides greater public scrutiny over augmentation and replacement options, potentially increasing the ability for TNSPs to discover innovative solutions to network constraints and constraining a reliance on ‘business as usual’ options
- leverages off existing institutional mechanisms (RIT-T and contingent projects) and so limits incremental administration and compliance costs.

However, the system does impose some additional costs:

- the extra process creates additional compliance and administration costs, which might be significant if most augmentation and replacement activities were to be covered
- it can reduce the ability of TNSPs to substitute between different projects (a significant advantage of well-functioning incentive regulation) for projects that are on the margins of the threshold.

As such, there is a tradeoff between the costs and benefits of subjecting projects to greater scrutiny. This tradeoff can be accounted for by only applying the revised RIT-T to projects that meet (or exceed) a threshold value. This would ensure that smaller projects do not incur disproportionate administrative and compliance costs, and that some flexibility to substitute between projects is retained, while still preserving the benefits noted above for larger projects that may present greater risks (and costs) of delays and windfall gains. Any criteria for the application of greater scrutiny would need to consider the:

- proportion of total capital spending covered, and the number of projects (in consideration of the administrative and compliance burden)
- degree of uncertainty associated with certain sized projects (Grid Australia (sub. DR91) put forward that for large transmission projects in particular, timing is critically affected by forecast demand, increasing the degree of uncertainty)
- potential to 'game' a threshold by repackaging groups of smaller projects. Lower thresholds will lend themselves more to such gaming as small variations in the definition or timing of the project could determine if it is above or below the threshold. Conversely, the inherently 'lumpy' nature of larger transmission projects suggests that higher thresholds are less likely to be gamed
- degree to which investment benefits are easily observable in the day-to-day running of the network (for example, where the benefits or costs of delay are easily observable, TNSPs are likely to have greater incentives to complete projects expeditiously. Where they are not, such as some long-term reliability and 'net benefit' driven investments, there are greater risks of investments being delayed or avoided)
- costs of the review system for all parties.

The most administratively simple, clear, and objective threshold to apply is one based on a dollar value. Based on information of the composition of projects over the next five year forecast periods provided by Grid Australia (table 17.1), a threshold in the order of $35 million would appear to be an appropriate starting point. This would capture 7 per cent of augmentation and replacement projects by number (limiting the compliance burden) and, more importantly, 54 per cent of the value of projects (ensuring significant projects are subject to appropriate scrutiny).

Table 17.1 **Grid Australia consolidated five year forecast project costs** [a]

Project size	Augmentation		Replacement		Augmentation plus replacement			
	$ million ($2012 or $2012/13)	Number	$ million ($2012 or $2012/13)	Number	$ million ($2012 or $2012/13)	Per cent share (by value)	Number	Per cent share (by number)
$0 to <$5 million	93	89	437	536	530	10	625	67
$5 million to <$35 million	532	60	1 409	178	1 941	36	238	26
>$35 million	999	21	1 914	42	2 913	54	63	7
Total	1 624	170	3 761	756	5 384	100	926	100

a Project costs and numbers are consolidated across different five year periods between 2012 and 2019, based on TNSP regulatory periods. The figures are sums of values for SP AusNet, TransGrid, Powerlink, Electranet and Transend. Augmentation figures do not include SP AusNet. The classification of replacement projects (whether large replacements are grouped as a single project or many different ones) varies between TNSPs.

Source: Grid Australia (sub. DR101).

In the first instance, using the revised input cost estimates from the AER's recent review (AER 2012u) would be a reasonable starting point, suggesting a threshold of $38 million. This threshold figure should be indexed annually in order to maintain its real value.

At the margin, there may be theoretical scope to 'game' this threshold by reclassifying projects as costing less than $38 million in order to avoid additional scrutiny. However, as noted above, the Commission considers that several controls would limit the scope (and incentive) for such gaming, notably:

- while TNSPs will be required to nominate foreseeable 'large' projects at the time of their regulatory determination, smaller (or new, unforseen) projects that appear likely to become 'large' as the time to invest approaches would be also be subject to the RIT-T
- analysis by AEMO in its various roles could be used as advice to the AER
- the AER's ability to conduct an ex post review (chapter 5) could identify egregious examples of overspending on transmission projects where the actual amount spent exceeded $38 million (effectively subjecting the process to an ex post RIT-T, creating greater risk for the transmission business)

- avoiding the RIT-T does not equate to avoiding scrutiny altogether. Instead, a project would become a part of the general revenue determination process.

Applying this threshold, in concert with the existing RIT-T arrangements, would see projects split into three tiers:

- $0-5 million: Projects are not subject to any form of RIT-T or transparency requirements. Such projects are dealt with entirely through the pre-existing general revenue determination (and detailed in TNSPs' annual planning report).
- $5-$38 million: Projects are subject to the 'streamlined' RIT-T (with fewer consultation requirements). This brings a measure of transparency, but minimises compliance costs. The revenue for such projects is determined through the general revenue determination.
- $38 million and above: Projects are subject to the 'full' revised RIT-T, with input from AEMO. The AER approves the revenue for the individual project through the 'contingent projects' process, not the general revenue determination.

RECOMMENDATION 17.3

The revised Regulatory Investment Test for Transmission, and the associated project-specific revenue determination, should be triggered when a project (or any of the considered options) exceeds a threshold value. In the first instance, this should be based on the current threshold for application of the full test ($38 million), which should then be indexed over time to maintain its real value.

Measuring reliability benefits

While most (smaller) transmission projects will be based on meeting probabilistically set reliability standards (chapter 16), for major projects (that is, those above the threshold), undertaking a RIT-T entails conducting a full cost-benefit analysis. Essentially, this involves 'reopening' the probabilistic reliability calculations, and using the latest available data (particularly regarding the value of customer reliability) to measure reliability benefits as a component of the overall cost–benefit analysis.

As noted above, this removes the need for a separate 'reliability driver' for the test, as all projects would now be justified on net benefit grounds.

Conducting a full cost–benefit analysis allows for a more detailed, tailored and up-to-date analysis of reliability (and other) benefits for major projects, and makes the selection of economically efficient major investments more likely.

RECOMMENDATION 17.4

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.

When a Regulatory Investment Test for Transmission is triggered for a major project, a full cost–benefit analysis involving a (public) probabilistic reliability assessment should be conducted.

17.4 Other potential improvements

Even if the RIT-T retains its current role, there are a number of issues and potential improvements to its detailed performance that were raised in the Commission's draft report. In the context of the RIT-T's revised, and more central, role as recommended by the Commission, ensuring that the test functions well takes on even greater importance.

Other means to improve 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 agrees with this principle. However, as noted earlier, absent the public consultation requirement (and consideration of 'competing' options involving investments in other regions), 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 commercial damage due to disclosing confidential material, would involve little additional compliance cost.[11] 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 19). In particular, where a wealth transfer is expected and repeated, it takes on characteristics of a long-term investment incentive or disincentive.

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.[12] 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 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 detailed 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 wider economic effects would allow the transmission business to count benefits that are not accessible for other industries. For instance, when hiring staff, a manager of a commercial business will only

[11] Examples of possible confidential material might 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.

[12] This issue was also considered by ACIL Tasman (2006).

consider whether that decision is cost effective for the business, and not whether it will reduce the regional unemployment rate. Were these broader concerns to be considered in the RIT-T, it might bias investment away from other sectors of the economy towards transmission projects. It would also require modellers to make difficult judgments 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 economywide impacts would require 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, p. 27).

In any event, adding the complexity of economywide 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).

RECOMMENDATION 17.5

The Regulatory Investment Test for Transmission should not be amended to include indirect effects of investment decisions.

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 (2011a) 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.[13]

[13] There will be a rent transfer, from generators to consumers but, as discussed above, these are not considered under the RIT-T framework.

- An improvement in the merit order dispatch. With market power, 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.

The Commission agrees with the framework provided in the Handbook, although it is unclear whether all of the information required for these types of calculations 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 'must consider the effects of climate change on demand (higher temperatures) and supply (severe weather events, water scarcity and bushfires)' (2008, p. 450).[14]

The Commission agrees that modelling methodologies should aim to represent the variables that have major effects on the decision in question. However, neither can these 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,

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[14] 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.

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 growth by adopting the Treasury's 'core' modelling forecast for the impact of the carbon price (AEMO 2012g).

The existing range of scenarios appears suitably broad, and is developed and updated independently of those who could have a financial incentive to game it. As such, the Commission considers that existing range of scenarios is 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 where both options are being considered with no pre-existing investment to bias the choice, the capital cost of building infrastructure to transport gas is significantly lower than that for electricity. Some estimates suggest electric energy is between 1.5 to 2.5 times more 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 directly through transmission charges, and indirectly through transmission losses or costs that arise from congestion (chapter 19).

As it does not explicitly consider gas transport alternatives as options, 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 best 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 19.

18 The role of interconnectors

Key points

- Interconnectors can be described in different ways.
  - Physically, they are a collection of transmission lines that join the regions of the National Electricity Market (NEM).
  - Functionally, they are a notional concept of the capacity to transfer energy between regions in the NEM. As the Australian Energy Market Operator has pointed out, they exist as mathematical representations within the dispatch engine of the capacity to transfer energy from one regional reference node to another (subject to network constraints and generator dispatch patterns).
- Interconnectors are an essential prerequisite for integrating the six, historically state-based, electricity markets into a single 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 NEM, and promote greater security of supply.
  - Therefore, problems with the NEM regulatory arrangements can affect interconnectors, with far-reaching consequences.
- While the capacity of any given interconnector sets an upper limit on the amount of power that it can transfer between two regions, other factors — such as the capacity of, and congestion on, state-based intra-regional transmission lines, as well as the regulation of the NEM — further limits how much power flows in practice.
  - It is the latter degree of actual *'interconnection'* that is policy relevant.
- Some have claimed that interconnectors are congested, limiting their potential to enhance the efficiency of the NEM.
  - However, investment in interconnectors and associated parts of the network involves significant costs, so that some level of congestion is 'efficient'.
- Evidence suggests that, given the existing network and the profile of demand, the current *physical capacity* for interconnection is appropriate.
- Underutilisation, especially in South Australia, and some instances of significant 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 NEM [National Electricity Market], 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 distribution network investment, there have been concerns about *under*-investment in interconnectors.

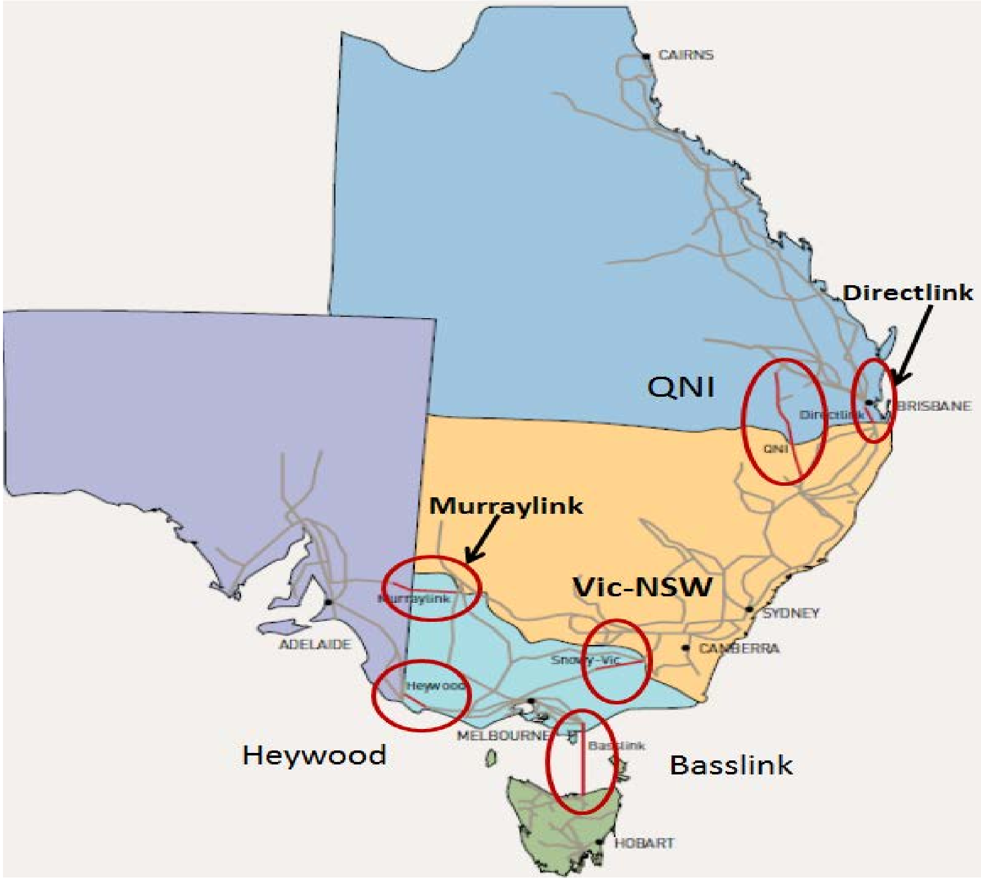
This chapter explores the potential benefits of interconnectors in the NEM, and the extent to which those benefits are being realised in practice.

18.1 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 19 can change the level and direction of flow.)

There are six interconnectors between the jurisdictions in the NEM (figure 18.1). Of these, three interconnectors (Basslink, Murraylink and Directlink) began as 'merchant' interconnectors, a topic discussed further in chapter 20.

Figure 18.1 **Interconnectors in the National Electricity Market**

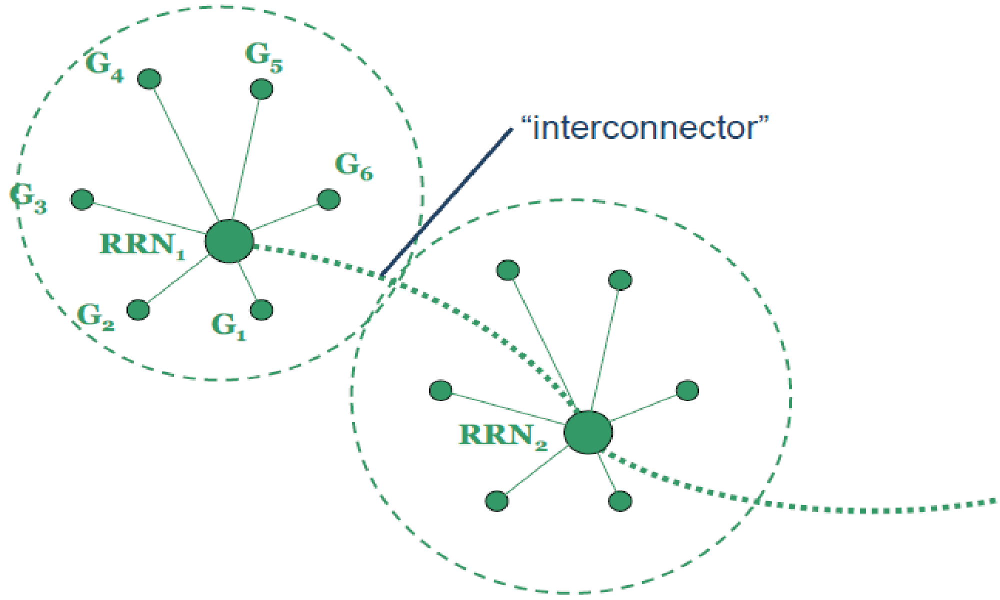


Source: AER (2009a, p. 54).

Interconnectors, interconnection and transmission

It is common to refer to interconnectors as just single transmission wires spanning regions, and this is how they are depicted in maps of the NEM (figures 18.1 and 18.2). However, referring to such 'notional' interconnectors is an abstraction from how interconnectors work. In fact, an interconnector can be composed of several transmission lines — of varying capacity and location — linking generation and load centres (figure 18.3).

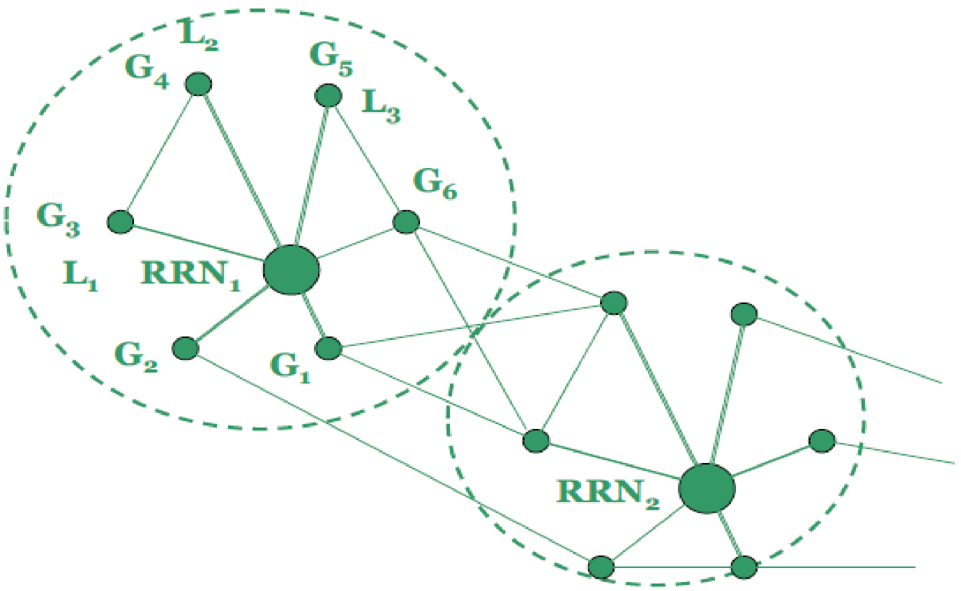
Figure 18.2 **Dispatch model representation of a notional interconnector**[a]



[a] 'G' represents generators, 'RRN' represents the regional reference node.

Source: AEMO (sub. 32).

Figure 18.3 **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 law[1] in an alternating current (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 18.1), 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, 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 its Transmission Frameworks Review first 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

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 direct current (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)

Table 18.1 **Interconnector capacity in the National Electricity Market**
MW

Interconnector	*Direction*	*Technology*	*Capacity*	*Peak observed flows*[b]
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 in the NEM dispatch engine 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 40ºC in Sydney and Adelaide, and 39ºC 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 (2011d, 2012f and pers. comm., 3 August 2012); Powerlink and Transgrid (2012).

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 AEMO's 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 18.1 still provide useful predictors of observed flows. For example, during the week of 30 January 2011, when temperatures in Sydney were over 40ºC, the flow on the interconnector was

5 Settlement residue auctions are described in chapter 19.

recorded as approaching, and in two instances, marginally exceeding, 1500 MW (AEMO 2011d, pp. 4-5).

The degree of linkage between interconnectors and intra-regional transmission lines has important policy implications. As the Australian Energy Market Operator (AEMO) pointed out, focusing on only the 'cross-border' wires would not allow a full consideration of the relevant policy matters for interconnectors:

> NEM commentary suffers a widespread misconception that interconnectors in fact are discrete assets joining two transmission network service companies, distinct from the meshed networks within each transmission company. This misconception can lead to a belief that national planning need be directed to these 'interconnector assets' alone, allowing local experts to work within their own territories with only marginal interaction with a national plan. However, … the limits to flow between regions have little to do with assets located near the border, nor even in the main pathways between load centres. (sub. DR100, p. 10)

Several other participants — including Grid Australia (sub. 22, p. 19), and the AEMC (sub. 16, p. 8) — agreed, and also noted the inseparability of intra- and inter-regional transmission capacity, investment and planning. 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.

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 sources of 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, presence of the Basslink interconnector assisted in avoiding costly blackouts in Victoria during the June 2012 earthquake by providing additional power to Victoria following the unexpected loss of nearly 2000 MW of generation (AEMO 2013e), 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. …. Interconnector constraints will be reflected in unnecessarily high, and more regionally differentiated and volatile, energy and emissions permit prices. (Garnaut 2008, pp. 446-7)

In the 2011 update to his review, Garnaut reiterated his concern about strong biases against interstate flows (2011b, p. 30). Previous reviews have also identified issues with interconnection (for example, Parer et al. 2002, p. 128). The International Energy Agency also identified ‘de-coupling of prices’ in adjoining states as an indicator of an emerging problem, and highlighted the importance of considering both intra- and inter-regional constraints (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 that 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 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. (p. 145)

In its 2008 Congestion Management Review, the AEMC concluded that congestion in the NEM was 'not a major problem' (apart from the then Snowy region), noting that it was 'unpredictable' and typically only caused mispricing for short periods before additional transmission or generation investment resolved the issue (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. For example, participants submitted that:

- the currently regulatory and planning framework could only deliver 'reliability-driven region-centric' investment (AER, sub. 13), and not a truly 'national grid' (AEMO, sub. 32)
- there is a need for greater coordination in investment planning to facilitate the role of interconnectors in transporting low-emissions energy between jurisdictions in the future (Clean Energy Council, sub. 31)

- there was a low level of recent investment in interconnectors, in contrast to intra-regional transmission lines (Major Energy Users, sub. 11). The Major Energy users also drew attention to what it saw as a 'considerable but unnecessary transfer of wealth from consumers to generators' (p. 12) facilitated by interregional separation (that is, when the interconnectors are unable to transport power from another region). Visy (sub. DR98) raised similar concerns.
- there was little need for greater interconnector capacity, but the issue lies with their use, as influenced by the use of market power, market design features and inadequate demand-side provision, among other things (Energy Users Association of Australia, sub. 24)
- AEMO further commented that the size of the problem caused by 'disorderly bidding' (chapter 19) warranted a 'generalist solution', and that:

  > Although the problem emerges in new locations of the NEM from year to year, it does not diminish. Most recently, otherwise minor events of congestion in the central Queensland region has frequently triggered widespread disorderly bidding across Queensland, severely impacting interconnector performance and producing negative residues. This is despite subdued Queensland demand which would be expected to reduce the prevalence. (sub. DR100, p. 11)

Others did not feel there was substantial evidence of any issues with interconnectors, and argued that:

- where interconnector investment is efficient, it is occurring in a 'timely manner', and that a lack of new projects may simply indicate that the framework is ensuring only efficient ones are built (Grid Australia, sub. 22)
- the absence of significant, sustained price separations between regions provided an indicator of sufficient inter-regional investment, but there could nonetheless be scope for enhancing transmission planning in the NEM (AEMC, sub. 16)

The views presented by generators also differed (box 18.1).

As the subsequent sections make clear, assessing the validity of such differing claims is not straightforward. Several important considerations bear upon an assessment of the evidence regarding the adequacy of current interconnection. These are outlined below.

Box 18.1 **Generators' views on interconnectors**

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 (discussed in chapter 19):

> 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 Forum 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 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)

18.2 Some conceptual considerations

The benefits of interconnectors must 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 17) contemplates a range of benefits that might arise from a new transmission investment (including interconnectors). These include allowing low cost generators to be dispatched more often, improvements in reliability, reductions in unserved demand, delayed or avoided investment in intra-regional transmission or generation assets, and the benefits from increased competition. The role of interconnection in managing congestion across the network is also important.

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 18.2).

At the same time, a welfare enhancing interconnection can create ‘winners and losers’ through its redistributive effects. Although these winners and losers generally ‘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). Further, under certain circumstances a large transfer (with no net efficiency effects such as long-term investment incentives) from consumers to generators would not be consistent with the National Electricity Objective.

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

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.

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)

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, congestion can be efficient 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)

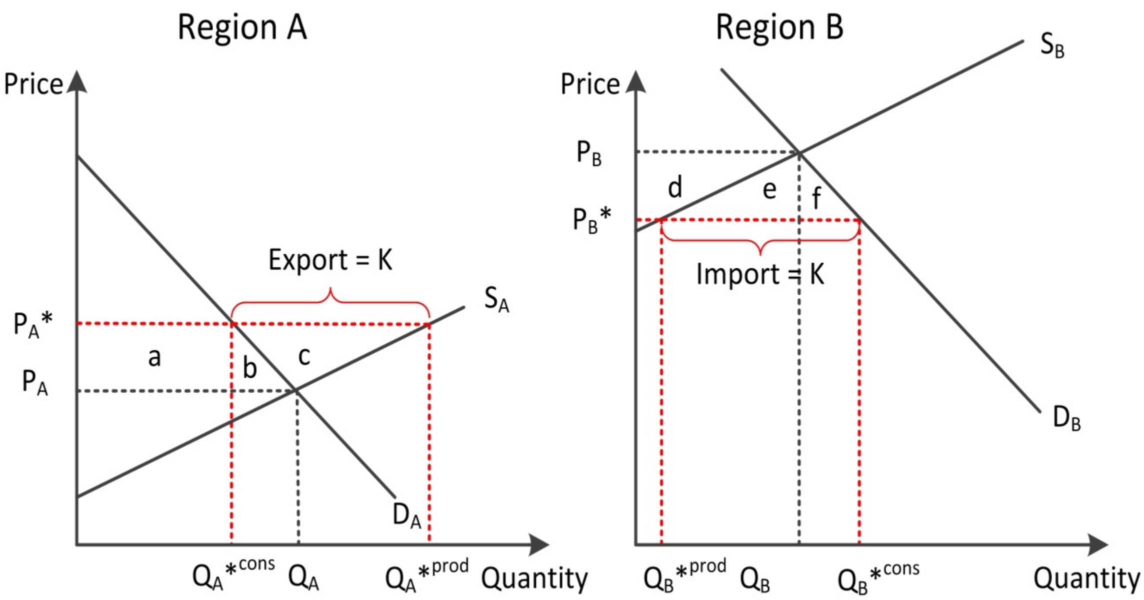
The implication is that a lack of new investment in interconnectors does not automatically mean that the regulatory framework has 'failed' — it might simply be that the costs of alleviating identified congestion would outweigh the benefits. This in turn means that the regulatory framework should not 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 judgments about the level of efficiency of any given investment. These questions are considered further in chapter 17.)

Box 18.2 **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 new generators can be built (and run) in one location at a lower cost than 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.

Source: adapted from Kapff and Pelkmans (2010).

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 et al. 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 interconnects to physically constrain or fail. (2002, pp. 129-30)

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 explored further in chapter 19.

Accessing renewable fuel sources

Garnaut (2008) 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. AEMO went on to suggest 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.

Where renewable energy sources are intrinsically efficient (that is, do not require subsidies) the ability to access them through interconnectors is likely to increase the scope for welfare enhancing trade of this nature as noted above. In this case, 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).

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 renewable energy requirements. In effect, interconnection will facilitate the use of the most cost-effective renewable resources across the NEM, rather than within each jurisdiction.[7]

But this would be very much a second best benefit. To the extent that mandatory renewable energy targets impose net costs, the best policy would be to remove or reform them, not seek to alleviate that cost through further investment in interconnectors. (Some renewable energy schemes are discussed in the context of distributed generation in chapter 13.)

18.3 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.

[7] There could still be gains from trading between regions, even in the presence of distorting state-based schemes. However, greater gains from trade (and potentially different trade patterns) would be available if there were no distortions at state level.

Cost–benefit analyses of potential interconnectors

Three interconnectors in the NEM (Heywood, QNI and Vic–NSW) are undergoing some evaluation by the relevant Transmission Network Service Providers (TNSPs), and AEMO in the case of Heywood, to determine what, if any, upgrades would be efficient. The information available from these analyses provides insights on both the adequacy of current interconnection capacity and the relative merits of different forms of upgrades (as well as on how the decision making process proceeds).[8]

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 (AEMO and ElectraNet 2011a) 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. 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 an earlier feasibility study (AEMO and Electranet 2011b) and favoured the addition of a third transformer at the Heywood terminal station, which would increase the interconnector's capacity from 460 to 650 MW. This option ('1b') 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).

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8 Electranet and AEMO published a Project Specification Consultation Report (PSCR) examining potential upgrades to the Heywood interconnector in October 2011, a Project Assessment Draft Report in September 2012, and a Project Assessment Conclusion Report in January 2013. 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 upgrading the Victoria to New South Wales interconnector. The analysis for this investigation is not yet public'.

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).

In January 2013, AEMO and Electranet (2013) released the Project Assessment Conclusions Report (PACR), the final stage of the Heywood RIT-T process. The PACR affirmed the choice of the third transformer at Heywood (option 1b). As no dispute was lodged with the AER by 22 February, Electranet will seek AER approval of the investment as a contingent project, and AEMO will put the Victorian components of the project to tender in the second half of 2013. The upgrade is expected to be operational in July 2016.

By indicating that a relatively incremental solution is likely to be the best option, the Heywood RIT-T process serves 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, 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 focuses 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 the project — which defers the costly Victoria–Tasmania component of the link — is still judged to have a net cost (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 the project would only be viable in 15 to 20 years from now (AEMO 2011d, p. 6-1). Indeed, AEMO was sceptical that the project could be realised at all in the current environment of jurisdiction-based planning, even if it had a net benefit:

> 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, AEMO's 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 allows for the continued evaluation of 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' 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 18.3 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 2009a, p. 143).

Box 18.3 **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 'mispricing', including the National Electricity Market Management Company Limited's (NEMMCO) Statement of Opportunities – Annual National Transmission Statements, work conducted by Biggar and NEMMCO. The following were reported in the Review:

- Biggar concluded that the NEM-wide incidence of mispricing has increased since 2003-04. He found that mispricing was a frequent and enduring issue at a relatively large number of connection points, stating that some 95 connection points were mispriced 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 mispricing from 2003-04 onwards. However, it also showed that over the study period (2001-02 to 2005-06) the number of connection points being mispriced 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 mispriced (constrained-off) than negatively mispriced (constrained-on). In 2005-06, the ratio between the two forms of mispricing was three to one.
- For intervals classified as 'mispriced', the average mispriced amount per interval was very high, ranging from around $500 to $1000 per MWh for generators that were positively mispriced and from around -$300 to -$6000 per MWh for generators that were negatively mispriced. 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 mispriced 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 mispricing 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 mispricing 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 offered by a generator and the regional price can diverge. They term this phenomenon 'mispricing', which creates dispatch risk and leads to disorderly bidding (AEMC 2008b, p. 8).

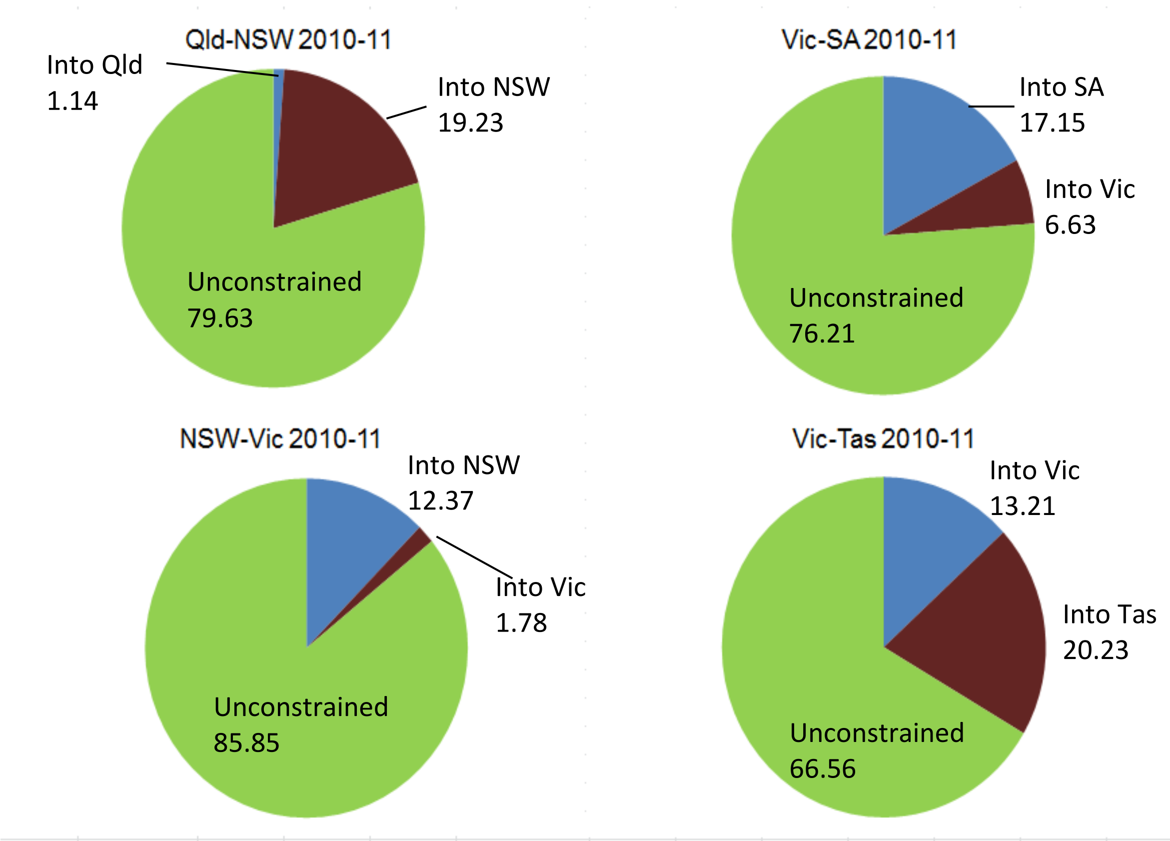
Price separations in the National Electricity Market

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.

The evidence in relation to frequency, scale and impacts of price separations is mixed. Most studies have focused on frequency of occurrence rather than the impacts of separations, the latter being of greater concern. For example, 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 18.4), 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 18.2).

Figure 18.4 **Percentage of interconnector time constrained, 2010-11**

Per cent of half hour periods



Data source: NGF (sub. 33, p. 6).

Table 18.2 **Price separations by interconnector, 2010-11**

Share of separations (%)[a], by price category

Line/direction	*<$0*	*$0<$50*	*$50<$100*	*$100<$200*	*$200<$500*	*$500<$1000*	*$1000<$12,500*
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.

Conversely, according to the AER, alignment of prices between regions (allowing for small differences due to natural transmission losses over long distances) is becoming less common. Prices were aligned 80 per cent of the time in 2001-02, 67 per cent in 2009-10 and only 61 per cent of the time in 2010-11 (AER 2011b, p. 34). This trend in the data could suggest increasing cause for concern regarding price separations (and that caution is required in drawing overly strong conclusions from the sort of snapshot data submitted by the NGF). However, as with the data submitted by the NGF, this alignment only examines the frequency of separation, not the effect that such separations have on broader market outcomes (such as counter price flows and on hedge markets) — the latter being more important for the efficient operation of the NEM. Indeed, multiple separations of little to no impact can be of less concern than isolated, unpredictable, instances of large

[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.

separations — depending on their effect on consumer behaviour, production and investment decisions, and risk management.

Recently, the AER (2012t) published further analysis regarding the costs caused by so-called ‘disorderly bidding’. This arises when, in the presence of congestion, generators’ bidding behaviour can increase the price in one region, while simultaneously causing ‘counter-flows’ (wherein power flows from the high-priced region to the low-priced region) across the interconnectors. That is, the behaviour of generators can cause, or exacerbate the effect of, price separations. The resulting counter-flows can occur at times when there is significant price separation (greater than $100/MWh) between regions, and gives rise to substantial costs that must be borne by consumers. Disorderly bidding and the AER’s analysis of the costs from particular instances are discussed further in chapter 19.

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.

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 18.3). 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 18.3 **South Australian interconnector capacity factors**

Heywood and Murraylink, shares of peak annual transfer capacity, per cent.

Year	*Capacity factor [a] in highest 72 settlement periods*		*Average annual capacity factor*	
	Vic to SA	*SA to Vic*	*Vic to SA*	*SA to Vic*
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. For example:

- 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

Another issue is that generating capacity in South Australia 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 (2012m) in its Rule change regarding potential generator market power in the NEM. 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. (2012m, pp. 41-2)

The AER also highlighted the behaviour of the Torrens Island Power Station:

> In only two of the 26 half hour periods where price exceeded $5000/MWh was more than 700 MW of the Torrens Island's capacity dispatched (Torrens Island Power Station's total capacity is 1280 MW). In over a third of these half hourly periods, *under 300 MW* of the total capacity of Torrens Island was dispatched. (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' (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 18.4). 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' (2012i, p. 1). And, in Biggar's view, there had been a 'significant' exercise of market power that 'persisted for three consecutive summers' (2011c, p. 61).

Box 18.4 **Generator market power in South Australia – the AEMC's view**

In examining the issue of generator market power in the NEM, the AEMC (2012m) 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 of prices against the long-run efficient level may be warranted' (AEMC 2012m, pp. ii-iii).

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.

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, or upgrading intra-regional lines that would increase effective capacity of the interconnectors, would be the sole solution (that is not to say that upgrading the degree of physical interconnection 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 19). 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 — 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.

Following the draft report, several participants — such as the AEMC (sub. DR89), Grid Australia (sub. DR91), the AER (sub. DR92), the NGF (sub. DR93) and AEMO (sub. DR100) — broadly agreed with the Commission's conclusions on the capacity for interconnection and the issues surrounding the use of interconnectors (finding 18.1).[13]

FINDING 18.1

The available evidence suggests that, given the existing network conditions, the current physical capacity for interconnection is appropriate.

[13] While agreeing that market design issues were inhibiting efficient interconnector use, AEMO (sub. DR100) also cautioned against making a definitive conclusion on interconnector capacity, and the underlying (state-based) networks until after the market design issues were resolved.

However, that the current physical capacity is reasonably appropriate does not necessarily mean that all market, planning, regulatory and incentive settings into the future are optimal. Nor does it mean that interconnectors are performing their intended role as efficiently as possible. Indeed, several concerns remain.

First, price separations can pose a problem. Substantial price differences between regions are infrequent, but isolated instances of large price differences can have significant adverse effects (including causing counter-flows on interconnectors, and complicating hedging arrangements).

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 judgments 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 (chapter 17).

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 19)
- whether, outside of the regulatory regime, there are any barriers that prevent the future provision of privately initiated (or 'merchant') interconnection? (chapter 20).

19 Efficient use of interconnectors

Key points

- The spot market in the National Electricity Market 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 higher-cost 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, 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 bid at prices that reflect 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.)
- The lack of effective inter-regional hedging products has contributed to the development of state-based electricity hedge markets. 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.
- Reporting 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 market 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 through promoting a greater degree of interconnection.

This chapter examines the operation of, and incentives set by, both the spot and hedge markets in the NEM.

19.1 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 pm on the day before supply is needed. They may submit rebids until five minutes before dispatch. Rebids may change the volume, but not the price of

generator bids are dispatched in 'merit order', with lowest price bids first, with progressively more expensive generation called upon until demand is met. 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 18, 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 following a system failure). 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 (in the energy market) to a lower-priced one.

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electricity offered (AEMO 2010f). Nonetheless, with a sufficiently large number of price bands within a schedule (and with rebidding of volume in other bands to zero) rebidding 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.

19.2 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 have all of their supply dispatched. Consequently, generators not affected by the constrained line must supply more power than usual. Given the operation of the 'merit order' dispatch, 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 National Electricity Rules ('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

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.

would have to share supply with higher-cost generators. This results in a higher overall cost to produce electricity for the region.

Box 19.1 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. That is, generators who compete for limited capacity — where their bids will not determine the spot price — will have an incentive for disorderly bidding (AEMC 2011f, pp. 210-12). This has been observed in bidding patterns by the AER (2010c, p. 3).

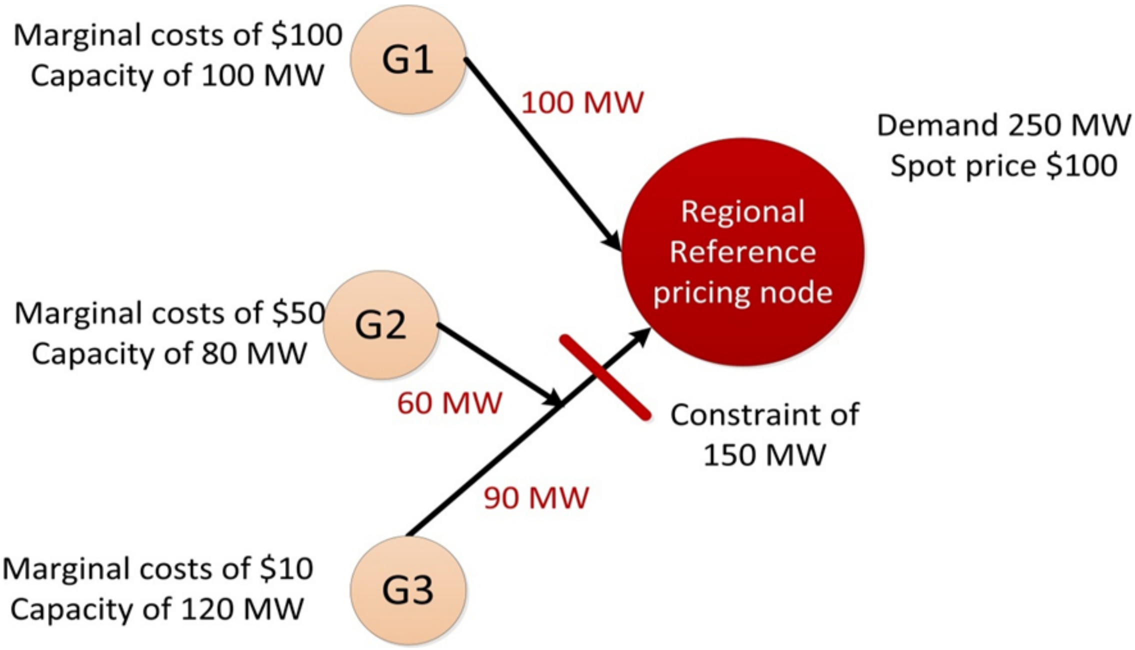
The intrinsic problem is that with transmission constraints, and with the spot price set elsewhere in the region, generators no longer face incentives to bid down to their marginal costs. The duration of constraints can vary — for example, an outage for a few hours, as opposed to the time to construct 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 Australian Competition and Consumer Commission (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 legitimate reasons for doing so.)

Though disorderly bidding can cause a range of problems *within* a region, for the purposes of this inquiry, the main focus is the potential impact on the performance of interconnectors (described in a simplified example in box 19.2).

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. They may buy hedge products such as 'inter-regional settlement residues', to attempt to align their returns with prices in the other region, as discussed below. However, current methods of hedging across regions 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 19.1 **Disorderly bidding within a region**



In the example above, the transmission line connecting G2 and G3 to the load centre at the RRN 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:

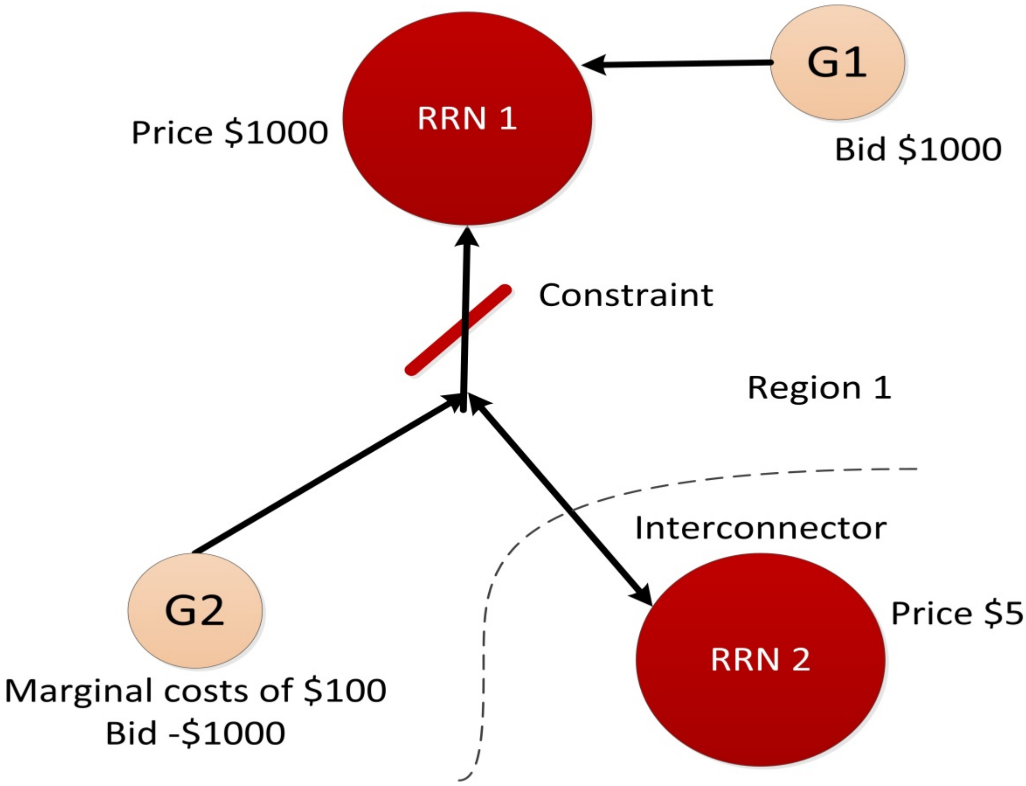
- G3: 90 MW (marginal production costs $900)
- G2: 60 MW (marginal production costs $3000)
- G1: 100 MW (marginal production costs $10 000)

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 19.2 **Disorderly bidding between regions**



As in box 19.1, 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, with 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 RRN 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 19.5) 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.

Following the Commission's draft report, several participants — including the National Generators Forum (NGF, sub. DR93), Hydro Tasmania (sub. DR96) and the Clean Energy Council (sub. DR97) — reiterated this view. They expressed concerns that disorderly bidding was not a 'material practical issue' (sub. DR96, p. 4) and that the Commission's proposed solution (discussed below) was 'far from proportionate to the problem' (sub. DR97, p. 4). In particular, the NGF submitted AEMO data to argue that the cost of congestion was falling and noted that the 'cost of $22 [million] in 2011 is very small compared to the energy turnover of the NEM of $5500 [million]' (sub. DR93, p. 7).[8] However, disorderly bidding gives rise to a range of costs.

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6 Such clamping is not always successful, primarily due to generators' stipulated 'rates of change' (ramp rates) 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. Reforms to generator ramp rates are discussed later in this chapter.

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 be manifested in different ways, for example, there is some evidence of generators withholding supply at times of import congestion in Norway (Mirza and Bergland 2012).

8 This figure is AEMO's estimate of the 'market impact' of constraints, calculated by summing the values from the 'marginal constraint cost' re-run of the dispatch engine. This re-rerun removes any violating constraint equations (and marginally relaxes some others) to examine hypothetical market outcomes in the absence on congestion. It is a static measure of short-run production costs only. AEMO (2012i) only provides data from calendar years 2009 to 2011, limiting any ability to examine trends. This may not be an accurate measure of productive efficiency given that it takes generators bids as reflective of their short-run marginal costs. To

The largest and most immediate effect of disorderly bidding is 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 10.30 am to 5.30 pm) 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.[9] AEMO concluded that:

> NSW prices between 10:30AM and 3:30PM averaged $90/MWh in the re-run against the actual average of $4917/MWh, which would have reduced pool settlement by about $300 [million]. (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 19.3).

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). While the wealth transfers are larger and simpler to quantify, there are some efficiency effects.

In the short term, productive efficiency is lower for the period of disorderly dispatch, 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.[10]

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some extent these bids would include instances of disorderly bidding, resulting in short run marginal costs being reported as -$1000 for those instances.

9 In contrast to the $22 million estimate, the $300 million revenue impact cited for one instance of disorderly bidding (AEMO 2010g) was calculated by holding the effect of the network constraint in place, but removing the rebidding of generators in response to it. This figure measures the market price effect, not production costs.

10 As noted in chapter 18, 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 19.3 **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).

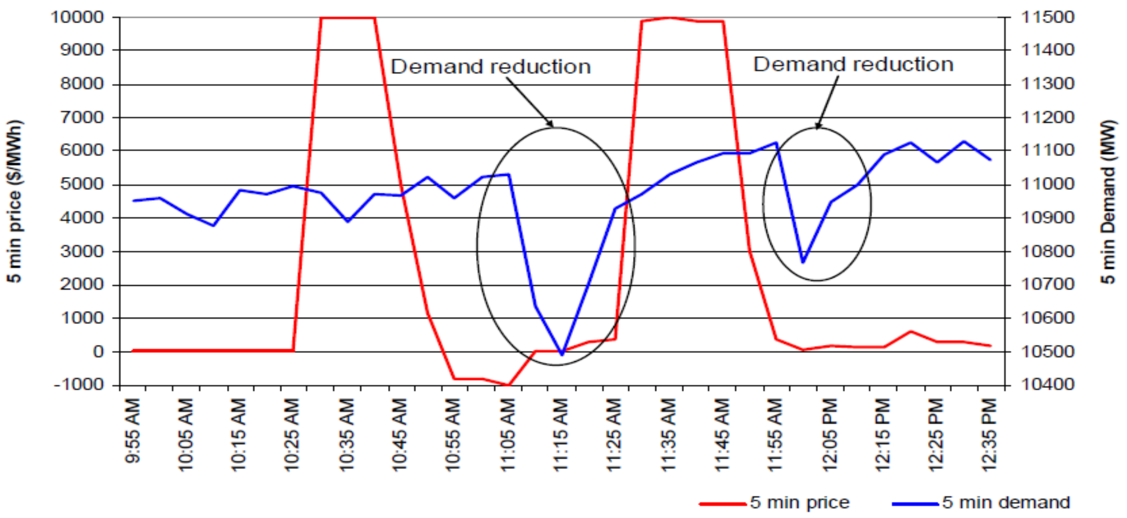
The figure below depicts prices during the morning of these overloads. In the face of the line constraint, the quantity of negative offers from generators increased, from 6200 MW at 10.30 am to 10 600 MW at 10.40 am (New South Wales aggregate demand at the time was just below 11 000 MW). The effects 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 six 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/MWh at 12.45 pm.

These constraints also reversed the flow of the interconnectors. The Qld/NSW interconnector 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).

Additionally, when interconnector flows are reduced, stopped, or indeed reversed, by disorderly bidding, it affects the ability of market participants to hedge transactions between regions (section 19.5). This causes greater uncertainty for hedging parties, increasing the cost of hedging and flowing through to higher electricity retail prices in the long run.[11]

While the productive efficiency costs in the short term may appear to be relatively small in the context of the NEM, they only represent one part of the total costs arising from disorderly bidding. In the long term, disorderly bidding causes a range of larger costs, though these are more difficult to enumerate than the short-term productive efficiency costs and transfers away from consumers.

First, the reduced certainty of dispatch (and increased price volatility) 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), and require existing generators to build a premium into hedge contracts to cover such risks.

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.

Accordingly, existing or new generators may be located 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 fired plant in Queensland was located to take advantage of the revenues created by disorderly bidding. The plant is located between the Queensland/New South Wales interconnector (QNI) and a congested part of the Queensland transmission network (AER 2010c, p. 12). The AER claimed that

[11] Disorderly bidding can have several impacts on hedging, and thus on retail prices. First, instances of disorderly bidding can increase the volatility of returns in the market, potentially increasing the costs of managing risks. Second, by reducing or eliminating the effectiveness of inter-regional hedging options, it can reduce the liquidity in state-based markets. Third, these effects may flow through to reduced levels of retail competition.

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).

The NGF disagreed with the AER's claims regarding Kogan Creek, and argued that the location was chosen because 'the coal resource is stranded from export markets, the mining costs are extremely low and the transmission access is superior to that in competing locations'(sub. DR93, p. 14). The NGF also submitted that Kogan Creek had a lower short-run cost than any New South Wales generator. While Kogan Creek may be less costly and, thus, it would be more efficient from a NEM-wide perspective to run, it is also located in area that allows it to take advantage of congestion, and cause the (short- and long-term) costs associated with disorderly bidding. Therefore, while Kogan Creek may not always be cheaper than every generator in New South Wales, under the current regime, whenever constraints occur, it will always have the ability to 'block' their supply across the interconnector.

This suggests that, even if some form of congestion pricing were implemented to correctly align incentives, generators such as Kogan Creek would be unlikely to alter their choice of location. However, there may be some cases where access to the transmission network is the marginal, and potentially deciding, factor for generators. As discussed below, an efficient transmission pricing system would account for all factors, encouraging generators to make a decision that appropriately considered all costs (including transmission costs and effects of congestion).

More recently, the AER (2012t) has analysed several incidences of congestion in Queensland, New South Wales and Victoria (box 19.4). The analysis focused on several incidents of disorderly bidding, and the resulting negative settlement residues. As the AER acknowledged:

> … the negative settlement residues are only one aspect of the inefficiencies that arise from disorderly bidding. There are larger impacts in terms of non-economic dispatch and through increasing the risk profile of all NEM participants, both customers and generators. (2012t, p. 13)

The AER concluded that the current market arrangements, which create the incentive for disorderly bidding 'are a serious problem' and that they are 'leading to significant inefficiencies and lessening competition between regions' (AER 2012t, p. 3). More recently, the AER also drew attention to events in Queensland in January 2013:

> In the first three weeks of January, for example, there were 80 occasions when the spot price exceeded \$300/MWh, with 16 of those over \$1000/MWh. These price spikes were not driven by excessively high demand but rather network constraints and the last

minute rebidding behaviour by CS Energy and Stanwell generators. Once again there have been persistent counter price flows from Queensland into New South Wales … leading to almost $8 million in negative settlement residues into New South Wales during January and February 2013. (sub. DR109, p. 1)

Box 19.4 **The impact of disorderly bidding on inter-regional trade**

The AER recently analysed the impact of disorderly bidding on inter-regional trade in the NEM. The analysis examined instances of disorderly bidding and their effect on inter-regional trade between New South Wales and Victoria, and between Queensland and New South Wales. In particular, it focused on the extent of negative inter-regional settlement residues (section 19.5) arising as a result of the disorderly bidding.

Congestion and counter-flows around the Snowy

From February 2010 to September 2012, there were 12 incidents of counter-flows into New South Wales that led to more than $150 000 of negative settlement residues. These occurred following incidents of disorderly bidding that were the result of congestion elsewhere in the transmission network — for example, between Dapto and Marulan. The negative settlement residues for these incidents ranged from $156 000 to almost $17.5 million, and totalled over $25 million. The impact was less severe for counter-flows into Victoria, with eight examples totalling nearly $9 million (the largest single instance was over $5 million).

The AER drew attention to the behaviour of generators in the presence of congestion. For example, on 16 October 2012, in response to a forecast price increase, Snowy Hydro and Origin Energy rebid over 3100 MW to prices near the price floor. This led to a substantial turn-around on the interconnector, from importing 706 MW into New South Wales, to counter-flows of 875 MW into Victoria.

Congestion near Gladstone, Queensland, and counter-flows to New South Wales

From September 2011 to October 2012, congestion around Gladstone led to 24 instances of counter-flows into New South Wales that each accrued more than $150 000 in negative settlement residues. The total negative settlement residue accrued was almost $8.3 million, with the largest single instance accruing almost $1.3 million of negative residue (a counter-flow of 1257 MW at a time when the maximum spot price in Queensland was $2080/MWh).

In analysing these instances, the AER highlighted the volatility in prices. For example, on 25 August 2012:

> Queensland 5-minute prices were extremely volatile, fluctuating between $1493/MWh and -$1000/MWh. The 5-minute price exceed $900/MWh on nine occasions and fell below -$300 on 21 occasions. (AER 2012t, p. 16)

As the AER noted, such volatility leads to uncertainty for the market, increases the costs of hedging and can deter new entry (section 19.5).

Source: AER (2012t).

The analysis also highlighted an additional cause of concern. As noted in chapter 18, due to the Rules and the presence of disorderly bidding, interconnectors can be of little use at times when prices in one region are highest — that is, precisely at the times when they could be of most use. Specifically, the AER drew attention to the proportion of trading intervals at times of high price differences where counter-price flows occurred across the interconnectors in the NEM (table 19.1). As the data indicate, since 2009–20, total counter-flows at times of high prices have been a more significant issue when prices were higher in Queensland than in New South Wales, and when prices in Victoria were higher than in New South Wales. Counter-flows appear to have been infrequent across the South Australia-Victoria interconnector (as noted in chapter 18, concerns in South Australia centre on issues of the exercise of more 'traditional' market power).

Table 19.1 **Imports across interconnectors during high price periods[a]**

Relative regional spot prices	*Number of counter-flow intervals (number of trading intervals)*					*Proportion of (total) trading intervals with counter-flows*
	2009-10	2010-11	2011-12	2012-13	Total	(per cent)
Qld > NSW	9 (41)	19 (19)	48 (60)	17 (17)	93 (137)	68
NSW > Qld	24 (131)	2 (63)	0 (5)	0 (20)	26 (219)	12
NSW > Vic	23 (172)	3 (108)	2 (6)	4 (5)	32 (291)	11
Vic > NSW	27 (69)	9 (9)	0 (1)	4 (6)	40 (85)	47
SA > Vic	1 (110)	0 (34)	2 (27)	1 (9)	4 (180)	2

[a] The table analyses metered interconnector flows for trading intervals where neighbouring region prices differ by more than $100/MWh. Data for 2012-13 were current at 14 November 2012.

Source: AER (2012t, p. 19).

An additional cost from disorderly bidding is to increase Transmission Use of System (TUoS) charges. As the AER noted (2012t, p. 21), proceeds from the settlement residue auctions go to Transmission Network Service Providers (TNSPs) to offset the transmission charges they pass on to users. To the extent that disorderly bidding nullifies the value of settlement residue auctions, and so reduces the proceeds from the auctions, there are fewer proceeds available and, as such, transmission charges borne by users will increase. Further, in cases of negative residues, the TNSP in the importing region is required to fund the shortfall through charges to its end users. Increasing the TUoS represents a transfer from consumers to generators, rather than a direct efficiency cost. However, as noted above (and in chapter 17), in the long term, repeated transfers can act as incentives and, therefore, can have associated real efficiency costs. Further, (as noted in chapter 18), unless there is some offsetting efficiency gain associated with such transfers, a system of rules that allows (and encourages) this behaviour would not be consistent with the National Electricity Objective (NEO).

Additionally, common ownership of even structurally separated generation and transmission could potentially delay responding to the need for a transmission upgrade.[12]

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. This can effectively 'entrench' existing inefficiencies, as a presently underutilised interconnector (even if due to quirks of the sort described above) can lead to future underinvestment.

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.

19.3 Potential solutions

An efficient solution to disorderly bidding should motivate generators to make bids 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 setting the price of their dispatched supply according to their 'nodal' (or local) price, potentially packaged with hedging options.[13] 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

[12] As noted in chapter 3, various state governments still have significant ownership of both generation and networks. However, there is no direct evidence that they have taken advantage of this for the purposes relevant to these issues.

[13] 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.

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 is examining 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 of the review (AEMC 2011f), the AEMC contemplated five packages for reform of generator access to the network.[14] In the second interim report (AEMC 2012j), the AEMC focused on two options:

- Optional firm access (OFA) in which generators can purchase from a 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. In this way, 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.

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.

[14] These five packages were: a minor clarification to the status quo, a Shared Access Congestion Pricing (SACP) 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).

The 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. 22-3) are as follows:

- *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-run incremental costs (LRIC) of increasing the network capacity over time. LRIC is one method of calculating (the broader principle of) long-run marginal cost (Marsden, Jacob and Associates 2004).[15] (Chapter 11 discusses the concept of long-run marginal costs in detail.)
- *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

[15] For the purposes of implementing the OFA package, the AEMC examined specific pricing methods. They defined LRIC and long-run marginal cost as different methods. In the technical appendix to the second interim TFR report (AEMC 2012n, pp. 42–3), the AEMC discussed the relationship between their definitions of the two measures (as well as 'deep connection charging'). There, they note that their definition of long-run marginal cost is a measure of the cost of transmission expansions that ignores 'lumpiness' in transmission investment. That is, if 347 MW of expansion is required, exactly 347 MW's worth will be built. Their measure of LRIC takes account of the lumpiness inherent in transmission networks and would only allow for expansions to be built when the next substantial increment (say 500 MW) was required. As noted in chapter 11, lumpiness of investments is an appropriate factor to take account of when considering which method to use to calculate a measure of the (broader concept of) long-run marginal cost. Therefore, the AEMC's use of LRIC is consistent with the Commission's preference for network pricing to be based on *a measure* of long-run marginal cost.

behaviour in a similar manner to congestion management mechanisms, and reduces incentives to disorderly bid.[16]

- *Inter-regional access:* Generators and retailers could purchase firm inter-regional access rights for a given amount of capacity on interconnectors. These 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 OFA 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

[16] In particular, the settlement mechanism has a similar effect to the shared access congestion pricing model (package 2 from the first interim TFR report).

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). This could also risk locking in current patterns of transmission use, thus potentially ‘locking out’ interconnectors. Avoiding the ‘lock in’ of the status quo is one consideration that should be borne in mind during the implementation process (discussed below).

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, p. 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.[17] The flowgate price is the marginal benefit of relaxing a constraint affecting the flowgate.[18] 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 (LMP) of the affected generators). Where a firm generator is the marginal generator at its node, and enters

[17] That is, the difference between a generator’s ‘entitlement’ (or access right) and their ‘use’ (or quantity dispatched).

[18] 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).

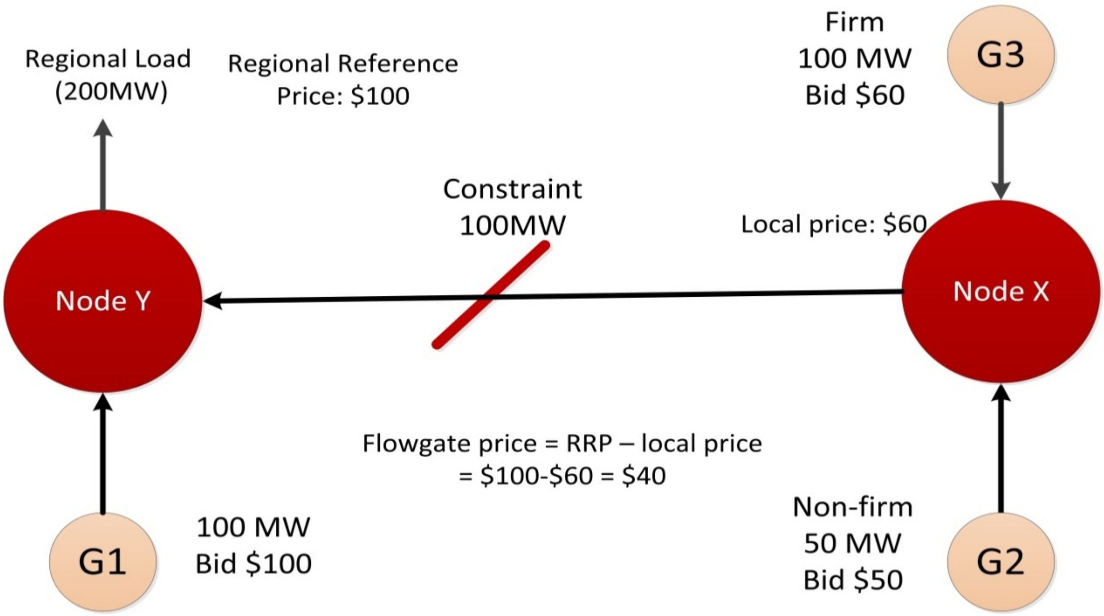
a bid equal to its marginal cost, the flowgate price will be the same as the profit margin that the constrained firm generator would receive from dispatching that MW. Therefore, firm generators' profits are the same regardless of whether they are dispatched or not, eliminating any incentive for firm generators to enter disorderly bids.

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 dispatch. 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 19.5).

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 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 LMP. 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 19.5 **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*$40 = $3000
- G3 receives energy settlement *plus* compensation: $5000 + 50*$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.[19] 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*: where 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,

[19] 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.

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 (provided they did so wisely) made a decision that was, 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 were directly aligned with suppliers', and that generators were 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 RRN. 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 and paying for firm 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 introduction of cost-reflective pricing 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, or the Commission's model of probabilistically-based reliability standards and contingent projects as recommended in chapter 16).

As discussed in chapter 16, 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 planning and independent probabilistically-based reliability standard-setting. 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.

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) noted, 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.[20]

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.

Further, an independent party with the knowledge of the network could be an additional source of information for generators, on issues such as the (long-term) upgrades required to meet firm access requests, and indicative costings of similar upgrades. This would limit the ability of TNSPs to price above cost. AEMO seems well suited to perform such a function. Such a role complements AEMO's existing national roles and the roles recommended by the Commission for AEMO to take on. These include roles as national reliability standard-setter, national planner and planner of last resort (chapter 16), and providing expert input to the AER in regard to the Regulatory Investment Test for Transmission (RIT-T, chapter 17).

Overall, the Commission considers that the benefits of the OFA package would still be significant even in the presence of transmission planning.

Design matters

As can be expected at the early development stage of a significant and complex model, several detailed design issues with the OFA package are, as yet, unresolved. Participants' responses to the AEMC's second interim TFR report have raised a number of issues with the OFA package. While the Commission does not intend to

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20 The AEMC (2012n, p. 87) also noted 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.

address every detailed matter relevant to an ongoing process, some of the criticisms of the OFA package, particularly those that relate to aspects of the market power possessed by TNSPs, bear discussion.

Market power — access pricing

As discussed above, under the OFA model, generators would be charged a price for firm access, based on LRICs. Where the access price is formulated appropriately, generators' incentives to locate (and bid) would be correctly aligned. However, there is an issue relating to responsibility for setting the access price.

The NGF (sub. DR93) raised concerns that allowing TNSPs to set the access prices would not be efficient, as it may present TNSPs with incentives to misprice the upgrades necessary to provide access, and would lack transparency, denying other stakeholders the opportunity to comment on assumptions made in the pricing process. These concerns could be exacerbated due to the fixed nature of access pricing, as the level and cost of access could vary over time, leaving generators potentially bearing a risk of an unnecessary cost. However, any risks that OFA could introduced must be compared with the risks inherent in the current system, including a significant volume risk for generators (undermining both their spot and hedge market returns) if they are not dispatched due to network congestion (and the bidding behaviour of other generators). Under the OFA package, generators can purchase a mechanism to manage this dispatch risk. Given that generators are sophisticated players in a workably competitive market (well-practised in managing risks from other large purchases such as plant and equipment), they are better placed than consumers (who would otherwise bear an increase in TuOS charges if additional investment were needed) to assess and bear such risks.

Both the Clean Energy Council (sub. DR97, p. 15) and the AER (2012w, p. 8) had similar concerns regarding the risk of a TNSP calculating the LRIC in a way that exercised market power (by charging generators too much), or in a manner that allowed them to build more assets than would be efficient (by charging generators too little).[21] AEMO also noted its concern that negotiating firm access with TNSPs

[21] Depending on the weighted average cost of capital (chapter 5), TNSPs may have an incentive to set a low access price in order to have more assets 'approved' through firm access requests as firm access prices are only an estimate of project costs, and the actual costs are rolled into the regulatory asset base at the next revenue determination. While the TNSP would carry the risk of costs exceeding revenue in the regulatory period that they are built, they could make up for this through higher revenues in future periods (chapter 5). Other measures, such as correctly estimating the weighted average cost of capital, or reviewing the value of assets entered into the regulatory asset base, may be able to limit this incentive.

would 'simply compound the disadvantages that generators face … [in] dealing with limited transparency from monopoly service providers' (sub. DR100, p. 12).

In terms of mitigating such disadvantages, the AER went on to suggest AEMO be given the role of determining access pricing, noting that:

> … AEMO will be able to take a nationally consistent approach and will be able to utilise its generation sector expertise. The AER also considers that there are benefits arising from AEMO's independence as a decision maker. (2012w, p. 8)

At the time of the second interim report, the AEMC envisaged that a 'consistent pricing methodology, to be applied across the NEM, would be developed during implementation of the OFA model' (2012j, p 32). They also acknowledged that the governance arrangements would require 'further consideration'. Of note, the (staff) technical report attached to the second interim report of the TFR, seems to contemplate the involvement of AEMO (though notes some drawbacks):

> … it would arguably be preferable for pricing of access requests to be undertaken by a NEM-wide institution which had a NEM-wide transmission model and demand and generation forecasts.
>
> On the other hand, …. [r]equiring a third party to undertake pricing in [the access procurement] process has the potential to make it much less effective and timely. (AEMC 2012n, p. 45)

The AEMC's presentation at a consultative forum (2012q, p. 29) also indicated that responsibility for access pricing was, at the time, an open question. Clearly this is an issue that should be resolved as part of the implementation of the OFA package. As noted below, the Commission considers that AEMO can play an informational role to allay the (valid) concerns that TNSPs could use their market power (and exploit information asymmetries) if they had the unfettered ability to set access prices. The involvement of AEMO should also encourage consideration of NEM-wide issues for any given access request.

The provision of information by AEMO is not a 'hard' control on TNSPs. However, as noted by both the AEMC (2012j, pp. 36-7) and the AER (2012w, p. 8), there may be scope to develop mechanisms that allow the TUoS (effectively, customer side) revenue cap to be adjusted where access pricing (rather than the quantity of access requested) led to a shortfall of revenue compared with costs. This could operate in a manner similar to the contingent projects process. Further, the AER could draw on AEMO's information in assessing the appropriate value of firm access expansions to roll into the RAB.

However, more direct (and timely) controls are likely to be more effective than relying on ex post methods. As the AEMC envisaged (2012j, p. 32), there would be a single, NEM-wide methodology for access pricing. This would be developed, essentially as a guideline, during the implementation of OFA. Once the guidelines are developed and the OFA model is in place:

- TNSPs could calculate pricing schedules according to these guidelines
- AEMO would analyse these prices (with particular consideration given to inter-regional effects) and publish their analysis, to inform both the market and the AER. The analysis could include benchmark costs of a range of transmission upgrades. Generators would also be able to access information of the costs of analogous (non-firm access) upgrades through the publication, by both TNSPs and AEMO, of RIT-T documentation.

In addition to initial guidelines for pricing, and the provision of information, one critical remaining issue is the degree of explicit price regulation required. While OFA should ensure that the highest-value users receive the access levels they desire, as noted above, allowing TNSPs sole responsibility for access pricing leaves the system open to the use of market power. There are several possible ways to address this:

- In line with the Commission's approach for general transmission planning (chapters 16 and 17), for 'major' requests (where at least one option to give effect to the request would involve a long-run incremental cost of $38 million or more), the AER could conduct a detailed cost–benefit analysis and approve the pricing of the individual access requests.[22] For small firm access requests, the AER could approve the pricing *schedules* (though not individual prices). The AER's decisions on access pricing should take account of the need to encourage investment, as well as encouraging efficient locational decisions by generators.
- Alternatively, the AER would approve the pricing *schedules* for all firm access requests (but not individual prices) in a manner analogous to the current pricing proposal process for general transmission pricing.[23] By not requiring the AER to approve any individual prices, this option avoids some ongoing administration and compliance costs. However, it also represents a 'lighter' regulatory control, relying instead on transparency and a limited degree of generator choice

[22] As access pricing reflects long-run incremental costs, the 'efficient price' is likely to be a stylised forecast of an expansion plan, rather than an imminent and identifiable single project (as is the case with the RIT-T).

[23] Such schedules would reflect stylised, indicative costs of a range of typical upgrades that would be required to give effect various levels of firm access requests (and also include components that varied with generator location). Of course, the *actual* individual price for any given firm access request would vary according to location and the particular combination of upgrades required. While not controlling the final access price, regulated schedules would act as both information to generators, and benchmarks that TNSPs would have to justify departures from.

(between which RRN they seek access to, and the quantity of access they seek) to curtail any excessive access pricing.

The choice between these two options (or indeed other alternatives that could adequately address market power issues) is complex, and depends on the degree of market power, the ability of transparency to overcome information asymmetries and the extent to which generators have any choice in their access requests. At this stage, it is too early in the development of the OFA model to determine which is the best mechanism for curtailing market power without incurring unnecessary costs. As such, the Commission considers that more analysis of this matter should occur in the lead up to the implementation of OFA.

Is firm access truly 'optional'?

Both the NGF (sub. DR93) and Biggar (2012) noted that the access settlement implications for non-firm generators competing with firm generators create a 'prisoners' dilemma' where, if one generator procures firm access, other generators would be worse off if they did not follow suit. Therefore, in anticipation of other generators' actions, it is likely that all generators will procure firm access.

The AEMC were aware of the incentive effects that the OFA package would create, and considered that OFA would lead to one of two equilibria, one where all generators are firm, and one where all are non-firm (AEMC 2012n, p. 83). They go on to note that, in the case where all generators are non-firm, it is likely that access costs will be low, which could encourage some generators to purchase access. This suggests that an equilibrium where all generators are firm is more likely.

In effect, purchasing firm access is 'optional' in the same sense that participating in the hedging market is for generators. That is, it is not a strict requirement to purchase access (or engage in hedging to manage risk), but commercial imperatives strongly encourage generators to do so. But OFA is not a mandatory 'entry fee' of a set amount for all generators that must be paid to participate in the market — generators can participate in the market without any access, or choose the amount of access they seek (whether partially-, fully-, or 'super-firm'), and manage their risks accordingly.[24]

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24 'Super-firm' access refers to a generator (of say 400 MW capacity) purchasing firm access rights at a level greater than its capacity (say 600 MW of firm access). As firm access rights are scaled back under certain adverse transmission conditions, purchasing 'super-firm' access improves the likelihood that a generator is able to dispatch its full capacity under a range of transmission conditions (AEMC 2012j, pp. 26-8).

It is an over-simplification to assert that the optional nature of the access means that no individual party will be strictly worse off. Indeed, the implementation of OFA would see a larger proportion of costs borne by generators, whether directly through purchasing firm access, or indirectly through exposure to liability to pay compensation as non-firm generators. But, as noted above, this transfer away from generators brings with it overall improvements in efficiency both in the short term (resolving disorderly bidding) and in the longer term (improving locational signals, introducing market-led transmission planning and improving interconnector planning).

Technical design matters

Several other issues were raised by participants in the AEMC's consultation process. While important, these issues are of a more technical nature. Accordingly, the Commission considers that they are more appropriately dealt with as part of the AEMC's ongoing process. Some of the issues are presented here for illustrative purposes:

- *Using flowgate pricing to determine access settlement*: The NGF (sub. DR93, pp. 9-10) highlighted the example of the Upper Tumut generator participating in at least 648 flowgates to access the New South Wales regional reference price. This leads to substantial complexity both in determining the access pricing (forward planning, considering the network make-up across those flowgates some 30 years into the future), and for hedging purposes (managing the risk of price differences) for generators. While the hedging market will adjust to make forward predictions of new pricing behaviours, the difficulty in accounting for multiple flowgates will affect the formulation of access pricing guidelines (and the prices themselves). As such, these matters should be carefully considered, and the subject of a transparent consultative process.
- *Generators with negative flowgate participation*: Biggar (2012, p. 5) highlighted the example where a generator has a negative participation (that is, if generator X dispatched power, it would *reduce*, not add to, congestion on line Y). In such circumstances, a different sort of mispricing occurs, and generators underprovide power. The AEMC (2012n, pp. 106-7) is aware of this issue, which does not stem from OFA itself, but from the treatment of 'flowgate support' generators. The AEMC (2012n, p. 16) suggested that a corresponding system of 'optional flowgate support' could be 'developed and introduced at a later date'.
- *Unscheduled generators and loads are excluded from the model*: Biggar (2012, pp. 6-8) also analysed some of the dispatch inefficiencies that could result from unscheduled generators (such as distributed generation) and load interacting with the OFA model. As with consideration of negative flowgate

participation including other market participants, particularly load, would be an appropriate consideration for a later review for any expansions to the OFA model.

- *Does the model apply to a substantial proportion of constraints?* Both Hydro Tasmania (sub. DR96) and the NGF (sub. DR93) submitted that one reason they felt that OFA would be ineffectual was that, according to their understanding 'generators are only purchasing firmness against thermal constraints … [which] only account for about $5m out of a total of $22m (22%) [of the costs of constraints] in the latest year' (NGF, sub. DR93, p. 7). However, based on its own consultations to date (AEMC, pers. comm., 12 March 2013), the Commission understands that OFA is intended to apply to those constraints that arise due to limitations on TNSP networks, and for which generators are not already compensated. This includes thermal and stability constraints. It does exclude some constraints, for example 'frequency control ancillary services' constraints (as they are not caused by *network* limitations), as well as 'network control ancillary services' and network support constraints (as generators are already compensated for such constraints).

Conclusion

While it is clear that the OFA package, as presented in the second interim report of the TFR, is by no means perfect (nor is its design yet fully complete), this should not prevent its eventual implementation. As identified in relation to market power issues, the problems are not insurmountable and should be able to be adequately considered, and remedied, during the implementation process. Nor are the problems large enough to outweigh the benefits available from introducing OFA.

The identified issues serve to illustrate that, when first contemplating significant and complex reforms intended to transfer to a new form of pricing for the market, care and time need to be taken, along with thorough consultation, to ensure that otherwise beneficial reforms do not lead to unintended consequences.

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 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 efficient 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 interconnector capacity may not be the most efficient overall solution 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 TFR report, 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 the implementation of the model, once finalised, should not face insurmountable obstacles. The implementation of OFA will likely transfer rents from some generators (and thus will be loudly opposed by those who expect to be affected), but that does not suggest inefficiency. In any case, the existing system leads to transfers that are arguably less defensible and, unless they provide some offsetting efficiency gains, may not be consistent with the NEO.

Implementation

As discussed above, OFA is a complex model. It is also an important reform for the electricity market. As such, it is equally important to allow time in the implementation of such a reform to develop the details prior to implementation, and to consult on any changes in order identify unintended consequences.

However, unnecessarily delaying the implementation of the OFA also risks sacrificing some of the benefits available from addressing issues such as disorderly bidding. Some, such as the AER (2012w, p. 9) have noted that disorderly bidding is increasing, and advocate implementing short-term measures before the OFA itself is implemented.

In the first instance, greater restrictions could be placed on generators lowering their 'ramp rates' (pace at which they can be backed off by the operator). Currently, the minimum ramp down rate is set at 3 MW/minute. A low ramp rate can allow a generator to benefit from disorderly bidding for an extended period of time, as the AER noted:

> … Snowy Hydro's Tumut facility is treated as a single unit by NEMDE [National Electricity Market Dispatch Engine] and has a capacity of 1800 MW. If it is operating

> at its maximum capacity … (which it can reach from zero in less than ten minutes with it ramp up rate of 200 MW/min), and bids in a 3 MW/minute ramp down rate, it will take 10 hours to ramp down to zero output. (AER 2012t, p. 22)

The AER originally suggested a change to the minimum ramp down rate to 3 per cent of a generator's capacity per minute (2012t, p. 22). This would result in larger generators being ramped down to zero at a much faster rate (18 times faster than currently in the example above). More recently, in recognition that some generators may have legitimate technical reasons for requiring ramp down rates of less than 3 per cent, the AER (sub. DR109, p. 5) suggest that generators instead be required to bid at their technical ramp rate at all times. This would require a change to the Rules, and to reduce uncertainty regarding particular rates for particular generators, would require an independent body to specify the definition of a technical ramp rate. While such changes[25] would lower the extent of the impact of any given instance of disorderly bidding, some incentive to disorderly bid would remain.

To this end, the AER (2012w, p. 9) also suggest that a 'short-term congestion management solution' could be implemented before the OFA package. This could be based on the Shared Access Congestion Pricing (SACP) model (package 2 in the first interim report of the TFR). The SACP decouples the incentives for generators by settling generators at their LMP, and assigning them a share of the intra-regional settlement residue. This share is determined not by the quantity that the generator is dispatched, but rather by the generator's availability, and the degree to which the generator's dispatch contributed to congestion. In doing so it removes the incentives for generators to maximise their dispatch in the presence of congestion, and thus prevents disorderly bidding.

In addition to the benefits from reducing disorderly bidding, implementing the SACP has a number of other advantages:

- Market participants would become accustomed to a form of access settlement.
- In addressing disorderly bidding, the SACP would also encourage a more efficient dispatch pattern by generators, and a more efficient flow along interconnectors. These flows could be used as the basis for granting transitional access (discussed above), reducing the risk that transitional access could 'lock in' any existing inefficiencies.[26]

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[25] The AER also suggested (sub. DR109, p. 6) that AEMO review the constraint formulation guidelines in order to address large changes to interconnector flows at times of congestion.

[26] Given the sporadic nature of disorderly bidding, basing allocations on a historical average, over a period of several years, could go some way to reducing the possibility of 'locking in'

- The Commission understands that much of the information relating to constraints that would be necessary for the SACP is already held by AEMO, who could also alter settlement systems relatively quickly (AEMO, pers. comm., 8 March 2013). Provided an expedited Rule change was undertaken by the AEMC, the time required to implement the SACP would be substantially shorter than for the OFA package.

Implementing the SACP in the short term would enable some of the benefits from reform to be accessed sooner than if OFA itself were the only reform. It also allows additional time to be taken to develop and refine the OFA package, reducing the risk of unintended consequences, a point also made by the AER:

> As a stepping stone towards OFA [SACP] would also provide valuable lessons to inform the design of the more complex aspects of the OFA model such as [TSNP] incentive arrangements. It would also provide real world insights for generators prior to the requirement for those generators to choose whether or not to commit to firm access. (sub. DR109, p. 3)

Importantly, implementing the SACP before the OFA package allows for a staged implementation process for such a major reform, reducing the degree of 'shock' to the market.

RECOMMENDATION 19.1

As an interim measure before the potential full introduction of the Australian Energy Market Commission's optional firm access package, a short-term congestion pricing mechanism as suggested by the Australian Energy Regulator should be introduced to the National Electricity Market.

Once the interim measure is implemented, time can be taken to fully develop the OFA model. This could be through a single, large Rule change process, involving several rounds of consultation. A more focused alternative would be a series of Rule change requests, each focused on a particular aspect of the OFA model. Importantly, although the available evidence to date (discussed above and summarised in box 19.6) suggests that the OFA model would be likely to deliver net benefits, this does not constitute a full cost–benefit analysis for what is a significant reform to the electricity market.

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inefficient flows (particularly if known instances of disorderly bidding were removed from the data before the average was calculated).

Box 19.6 Categories of costs and benefits from optional firm access

There is a range of costs and benefits arising from the OFA model. Importantly, transfers (including access fees to be paid by generators) are generally not considered. But the *effect* that a transfer has on (short-term) efficient dispatch and long-term productive and allocative decisions should be included in any cost–benefit analysis.[27]

Cost of optional firm access

- *Implementation costs in developing the OFA model*: A one-off cost involving the administrative costs of reviews, Rule changes, and consultations.
- *Implementation costs in changing the dispatch process*: A one-off, relatively minor, cost to adjust the dispatch engine. Note this cost would also be required for any interim congestion pricing.
- *Adjusted dispatch processes, bidding and monitoring*: An ongoing cost, as generators must adjust their bidding to account for new pricing structures. Under the Commission's recommendation, this would include administrative costs of monitoring bids by AEMO and the AER, an incremental increase on current practice.
- *OFA access pricing calculations and regulation:* An ongoing cost, borne by TNSPs, AEMO and the AER.

Benefits of optional firm access

- *Improved hedging between regions and reduced counter-flows*: Improving flows along the interconnectors can reduce costs to consumers from negative settlement residues (AER 2012t) and allow for a better functioning and more 'national' hedging market (below), reducing the cost of risk management.
- *Reduced price fluctuations:* Even isolated instances of disorderly bidding can cause price 'spikes'. Eliminating these reduces overall risks, and thus the costs of hedging.
- *Improved long-run generator location decisions*: Improved coordination between transmission and generation investment can lead to lower overall transmission costs. This saving only manifests when existing spare transmission capacity is exhausted, and as such, in present value terms could appear small at this stage.[28]
- *Improved short run efficiency of dispatch*: While there are difficulties in assessing an appropriate counter-factual, a conservative estimate (AEMO data put forward by the NGF) of the cost of congestion was $22 million.
- *Reduced prices and improved allocative efficiency*: While largely a transfer, to the extent that users respond to a reduction in price (away from a distorted level), there will be some allocative efficiency gains from improved decisions by electricity users.

[27] As noted above, some transfers can, over time, take on characteristics of incentives where parties can expect and respond to them. Additionally, some transfers can be inconsistent with the NEO, that is, where they transfer away from consumers, and do not have any offsetting efficiency gains that would be in their long-term interests.

Therefore, in order to properly assess the likely net benefits of the OFA model, and to demonstrate its consistency with the NEO, the Commission considers that the AEMC should conduct an initial cost–benefit analysis of the OFA model before its detailed implementation planning is commenced.[29] So that this does not unnecessarily delay the implementation of the model, such an analysis should be completed during 2013.

At a later time, during the more detailed implementation of the OFA package, this cost–benefit analysis should be updated to focus on the additional costs and (long-run and likely larger) benefits available from moving from the interim congestion pricing (after it has been operational for at least two years) to the OFA itself.

While, on the basis of the current evidence, a prima facie case can be made that the implementation of the OFA model would lead to net benefits, there are some additional considerations that the Commission believes should be noted.

First, OFA implements new pricing arrangements and, as such, 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.

Second, as discussed above, another useful addition to the model would be for AEMO to provide information to firm access applicants and the AER relating to required upgrades and indicative costs. By easing the information asymmetries faced by generators when dealing with monopoly TNSPs, such information provision could alleviate concerns regarding the use of market power. Using AEMO to provide information for firm access applicants and the AER would be consistent with the Commission's recommended role for AEMO in other areas such as the RIT-T, and particularly new generator connections.

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[28] While not directly analogous to OFA, modelling the introduction of transferrable financial transmission rights into the NEM indicated small, but positive, net benefits related to improved location decisions by new generators (IES 2012).

[29] While the nature of some of the costs and benefits from OFA may be difficult to quantify, methods such as those used to examine competition benefits in the RIT-T could be employed to examine the effects of changes in bidding behaviour. Further, international experience in conducting cost-benefit analyses for nodal pricing (for example in relation to the introduction of nodal pricing in Texas (CRAIRC 2008)) can be drawn on and adapted for use in modelling the NEM.

This would complement the additional elements of monopoly regulation envisaged by the AEMC as part of the OFA model. With these additions, and subject to the completion of a cost–benefit analysis, the Commission supports the OFA model in principle.

RECOMMENDATION 19.2

Provided that cost–benefit analyses show net benefits (including incremental net benefits in moving from short-term congestion pricing), and once technical matters have been resolved, the Australian Energy Market Commission should commence implementation of the optional firm access package for generator access to the transmission network.

- ***It should operate for a period of at least 10 years.***
- ***The Australian Energy Market Operator (AEMO) should provide information to applicants for firm access and the Australian Energy Regulator relating to the (long-term) upgrades required, and benchmark indicators of their cost.***
- ***Optional firm access should be monitored by AEMO 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 implementation of OFA is a substantial exercise itself, 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.

19.4 More fundamental reforms

Nodal pricing — theory

OFA appears to provide 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 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 OFA 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.[30] Alternative models include 'generator nodal pricing' where generators are 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 the following:

- 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

30 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, the New Zealand Electricity Authority (2012) expects the first auction of inter-island FTRs to be in early May 2013.

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 over time.)

- *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 and 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).

Nodal pricing in Australia?

Nodal pricing in the NEM was proposed in a major review 10 years ago (Parer et al. 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 a major obstacle (though governments could choose to ameliorate the impacts through transparent community service obligations). 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 and properly accounting for location.

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 19.7).

Box 19.7 **The AEMC's National Locational Marginal Pricing package**

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).

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 are likely to cause equity concerns. However, as noted elsewhere in this report (chapters 11 and 14), the Commission considers that such concerns should be dealt with by more transparent and targeted assistance for particular customer groups, rather than uniform (but not cost reflective) pricing. Doing so would alleviate distributional concerns, while preserving the efficiency gains available through (cost reflective) price signals. Providing information to 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.[31]

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 FTRs, a significant issue for the New Zealand market. The introduction of nodal pricing would also require consideration of governance issues, particularly if the market's departure from a regional structure lends further weight to NEM-wide transmission planning.

While transition costs are a relevant consideration for judgments 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. Indeed, some have noted that the OFA model can be characterised as 'a form of nodal pricing for a subset of generators' (Biggar 2012, p. 2). 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 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

31 While the retailer would face cost-reflective nodal prices in the wholesale market, consistent with the Commission's recommended approach in chapter 11, they could then develop a range of retail offerings for consumers (enabled 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. As the retailer faces cost-reflective prices in the nodal market, it will have an incentive to structure its overall basket of offerings in a manner that reflects the costs it faces. As such, while some customers may face flat tariffs, overall the summed consumption represented by the retailer should reflect costs.

exact form of nodal pricing involved, the structure of FTRs (particularly given the evolution of OFA 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.

Importantly, the review should consider if other, smaller, changes to the OFA package could achieve largely the same benefits as nodal pricing, with lower transition costs. Examples noted above include incorporating load (the demand side) and unscheduled generators into the OFA model, as well as the potential for any contestability in the provision of OFA to new transmission elements linking to an existing network such as an interconnector or a new load (for example, a mine).

RECOMMENDATION 19.3

After the optional firm access package has been operational for 10 years, a review should be conducted to consider whether the introduction of nodal pricing is warranted on cost–benefit grounds, or if other reforms (such as alterations to the optional firm access model) offer greater benefits. The review should have particular regard to the structure of the National Electricity Market at the time, the views of consumers and other stakeholders, and any remaining barriers to the introduction of nodal pricing.

A timeline for reform

As discussed above, the Commission considers that there is the need, and scope, for substantial reform to the NEM, in relation to generators' access to the transmission network and bidding in the spot market. While the reform required is substantial, there are benefits to participants from phasing in the reforms through a staged implementation process. The recommendations above discuss this process. The timeline for this process would be as follows:

- By the end of 2013: complete an initial cost–benefit analysis of the OFA model to confirm that detailed implementation planning should commence.
- Within two years (in 2015): implement a short-term congestion pricing mechanism, based on the SACP model.
- Over the next five years (2013–18): conduct extensive consultation on the detailed plan for the OFA model. Based on the detailed plan, and at least two years of operation of congestion pricing, conduct a more detailed cost–benefit analysis, including the incremental benefits of moving from congestion pricing to the OFA model. Provided this shows a positive net benefit, implement the OFA model (by 2018).

- Allow OFA to operate for 10 years.
- After this 10 year period, begin a review to determine if nodal pricing or other, more incremental, reforms are justified.
- Following the judgment of the review, take at least one year to design the details of any reform.
- Allow a transition period of at least two years if nodal pricing is recommended.

19.5 The hedging market

Spot market energy 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'). Electricity hedging is a key part of the efficient operation of the NEM, and questions of market design need to consider the impact on the efficiency of the hedging market. In particular, outcomes in the hedging market can affect actual energy flows including 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 19.8).

One way to manage this risk is through settlement residue auctions (box 19.9) 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, IRSRs 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. As the AER noted:

> … disorderly bidding has created the risk that SRAs [settlement residue auctions] are designed to manage, whilst simultaneously reducing the value of that risk management tool. … the reduction of firmness in SRA units imposes potential long term costs on market participants and end users. (2012t, p. 21)

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 this inquiry.)

Box 19.8 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 they use for trade, even if the spot price (P) is different.

If the spot 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 spot 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.

(Continued next page)

Box 19.9 **Settlement residue auctions (continued)**

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 settlement residue auction process corroborates this perspective. Were IRSRs used as an effective hedging instrument, buyers would be willing to pay a premium to manage risk (in the long term), just as with other insurance products. Accordingly, it could be expected that the receipts from buyers (that is, the auction revenues) should, over the long term, be greater than the settlement residues paid out by AEMO.[32] However, the evidence does not appear to support this (table 19.2).

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.[33] 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.

[32] A point made by AEMO (sub. 32, p. 26).

[33] 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.

Table 19.2 **Historical results of settlement residue auctions**

Auction	*Residue distributed*	*Auction proceeds*	*Payout rate*
	$ 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	43.5	18
2012 Q2	9.5	16.9	57
2012 Q3	13.1	19.4	67
Total	**599.3**	**436.1**	**137**

Source: AEMO Auction Reports (AEMO website).

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 on 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 make it more difficult for a state to act as a net producer of electricity in the NEM (despite any potential natural cost advantages such as availability of cheap coal or gas resources) 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.

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 19.10 sets out some of the claimed forms and impacts of such market power.

Box 19.10 **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,[34] 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,[35] 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 with 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.

[34] *Australian Gas Light Company v Australian Competition & Consumer Commission (No 3)* [2003] FCA 1525

[35] A discussion of the types of hedging contracts that different generators tend to trade can be found in appendix C.

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. 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 might, in theory, 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 would 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 understand the incentives behind generator bids, which in turn could improve the accuracy of forecasting involved in 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.

Reforms in this area need to be seen in the broader context of ongoing reforms of the derivatives market, which were announced at the G20 summit held in Pittsburgh in 2009.[36] These reforms, which were further developed in a consultation process undertaken by the Council of Financial Regulators, aim to increase the use of financial market infrastructure[37] in the derivatives market (COFR 2012). While the main goal of this reform is to achieve financial market stability, the report noted that the reforms would also ‘help detect market abuse’ (p. 3). The report concluded that

[36] Following this, the Australian Government announced in it will be introducing legislation to the Corporations Act to implement these commitments (Treasury 2012).

[37] The term Financial Market Infrastructure refers to a centralised system used for the purposes of clearing, setting or recording financial transactions.

while there were significant benefits to financial market reforms, ‘in the first instance, industry-led solutions should be the preferred route to increasing the use of centralised infrastructure within the Australian OTC [over-the-counter] derivatives market’ (p. 2).

In the context of the Australian NEM, an industry-led movement to increase the use of a centralised clearing process would be beneficial, but to take full advantage of this resource, regulators must be provided with information, and make use of it.

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.[38] 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 (Parer et al. 2002) and the Energy Reform Implementation Group (ERIG 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.

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[38] 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.

- 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 model 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 reside auctions as a second-best option.

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).

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, now called 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 110 kV 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); Kapff 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, pp. 1-2)

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 scheduled[2] 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 of the National Electricity 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:

> Net revenue = PB × FB – PA × 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 = RP × 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 an MNSP can earn is:

> \$35/MWh - \$25/MWh) X 400 MW = \$4000/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 co–existence 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 that 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 2003, 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 services.[4] (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. 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,[5] where the regulators have liberalised their regimes to

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-West Cables between Great Britain and Ireland; and the Arnoldstein-Tarvisio interconnector between Austria and Italy (Cuomo and Glachant 2012).

allow merchant investors to operate (appendix E). A number of merchant transmission projects have developed in response to these actions.

In Australia, 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 average annual price differentials were over $100/MWh (shaded price differentials in table 20.1). Average annual price differentials of this magnitude have not been evident since, although large differentials may appear occasionally in average monthly, including peak, prices (table 20.2).[6]

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	18.70	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 estimates based on AEMO (2013a).

6 The focus here on inter-regional price differences is about the extent to which they mount a convincing business case, based on the potential revenue returns, for merchant interconnectors to enter the NEM. However, as chapters 18 and 19 note, disorderly bidding from generators can prompt large but infrequent inter-regional price differences (or 'separations'), which can lead to significant inefficiencies in the NEM (such as causing counter-flows on interconnectors and deterring inter-state hedging arrangements).

Table 20.2 **Regional differences in recent average monthly (nominal) prices and average monthly peak (nominal) prices**[a, b]

$/MWh

Month/ Year	*NSW–Qld*		*NSW–SA*		*NSW–Vic*		*Vic–Tas*		*Vic–SA*	
	Price	Peak price	Price	Peak price	Price	Peak price	Price	Peak price	Price	Peak price
Jul 12	2.67	2.74	13.5	23.63	7.23	16.06	14.23	22.61	6.27	7.57
Aug 12	3.68	0.24	5.92	6.31	1.64	0.30	8.54	10.10	7.56	6.61
Sep 12	0.09	1.79	1.05	6.99	0.73	6.67	14.02	19.40	0.32	0.32
Oct 12	4.56	6.10	6.11	5.85	5.80	5.97	7.65	9.81	0.31	0.12
Nov 12	2.68	1.54	8.36	16.20	20.30	46.33	26.60	57.19	11.94	30.13
Dec 12	9.34	22.79	3.6	10.42	2.37	8.36	5.48	12.46	1.23	2.06
Jan 13	105.34	120.05	8.57	21.03	3.71	12.14	2.69	19.00	4.86	8.89
Feb 13	3.93	13.21	0	2.35	2.56	0.96	3.77	7.96	2.56	3.31

a Prices are absolute differences in regional reference node prices. **b** Peak prices recorded between 7.00 am to 10.00 pm (eastern standard time) on weekdays, excluding holidays.

Sources: Commission estimates based on AEMO (2013b).

This may 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 lasting chilling effects on the confidence of investors regarding the potential to make commercial returns from merchant interconnectors relative to regulated interconnectors.

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 19 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. The Australian Energy Market Commission's proposal for optional firm access discussed in chapter 19 promotes a form of financial transmission rights. The general role played by physical and financial transmission rights in relation to merchant investment is discussed further in the next section.

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 an 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 — including the Commission's proposals to introduce more rigour in the RIT-T process — are in chapter 17.)

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. Under the RIT-T, a transfer that devalued a merchant interconnector would not result in the rejection of an investment that showed overall net benefits.

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.

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 year to January 2013, the payments made by AEMO for FCAS totalled around $24 million (based on Commission estimates using data from AEMO 2013c).

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 energy transfer but not that of 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)

Box 20.4 **Frequency control ancillary services**

AEMO is responsible for ensuring that the power system operates in a safe, secure and reliable manner. 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 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 case for this to 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 an MNSP (2012p, p. 2).[7] If the 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.

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7 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'.

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. Other options to address disorderly bidding include the introduction of congestion pricing in the short term, optional firm access in the medium term and, potentially, consideration of nodal pricing in the long term (discussed in chapter 19).

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*.[8] 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 could potentially take measures to ensure that Hydro Tasmania does not direct 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

8 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.

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).

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 an 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 then *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' some participants raised the absence of explicit property rights for merchant transmission (AEMC 2011i, p. 5).[9] They claimed that a lack of

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9 These participants included the AER, EnergyAustralia, Macquarie Generation et al., and the NGF.

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 (NGF), 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. (2010, p. 15)
- The provision of property rights over merchant transmission has the potential to encourage greater investment in transmission by private investors … (2010, p. 10)

As discussed in chapter 19 in relation to disorderly bidding by generators, the AEMC is considering access rights for generators (and for MNSPs) as part of its Transmission Frameworks Review (AEMC 2011b, 2012j, 2012n). In its second interim report (2012j, n), it set out two options for generator access to the regional reference price: 'non-firm access' — which basically clarifies the status quo 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 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 an MNSP in the importing region is the same as for a generator. An MNSP would then be able to decide how much firm access to procure using similar criteria to a generator.[10]

Inter-regional access. The AEMC's proposal enables 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

[10] A MNSP can flow power in both directions and so there are potentially two importing regions in which it might seek firm access.

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 MNSPs to not only establish property rights over their merchant interconnectors, but to acquire them in respect of other parts of the transmission network.

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'.[11] 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).

[11] 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, proposed, 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).

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. Connection arrangements are discussed further in chapter 16.

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 NGF 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 into 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 [AEMC] 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 were 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 valued 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 ensured its costs were efficiently allocated across all beneficiaries, or that it were constructed to an efficient capacity.
- Even if a beneficiary pays approach were mandated (requiring all 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 were 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 in the NEM.

21 Governance

Key points

- Effective governance of the National Electricity Market (NEM) and its institutions is critical to meeting consumer interests. It affects network revenue and price determinations, network planning, the speed of reform and, accordingly, the ultimate cost to consumers.
- Governments and stakeholders have expressed concerns about the governance of the Australian Energy Regulator (AER), including its accountability, capability, communication with stakeholders, independence from the Australian Competition and Consumer Commission (ACCC), and transparency.
- Many of these perceptions are not backed by solid evidence and may reflect the usual tensions between an economic regulator and the parties it regulates. Others have more foundation, but can be remedied to ensure that the AER can assume the role of being the single national energy regulator.
  - While the AER is strongly independent from industry or government influence, perceptions of too close a link with the ACCC and a lack of transparency would be addressed by giving the AER more control over its budget and resources, and making it more accountable for how it manages those resources.
  - Concerns about resourcing and capability themselves will largely be addressed by additional funding announced by the Australian Government in late 2012.
  - An independent review of the AER should assist in addressing any remaining limitations in its operations, and would address any ill-founded perceptions about the organisation.
- Establishing the AER as a separate agency from the ACCC is not justified at this stage. However, a follow-up independent review of the AER should occur in 2018 to examine whether the recent reforms have had the desired impacts and, where they have not, consider other changes that might be beneficial, including the possibility of structural separation.
- The Australian Energy Market Commission (AEMC), the Australian Energy Market Operator and the new proposed National Energy Consumer Advocacy Body should be independently reviewed by 2018. All NEM institutions should be reviewed, thereafter, every 10 years.
- The participation of consumers in NEM policy, regulatory, Rule change and review processes is fragmented. Recent decisions by the Australian Government and the Standing Council on Energy and Resources (SCER) to create representative consumer bodies will address some of these deficiencies. However, on efficiency grounds, the proposed National Energy Consumer Advocacy Body should incorporate the overlapping functions of the Consumer Challenge Panel and the Consumer Advocacy Panel.
- The National Electricity Law should be amended to require the AEMC to undertake an accelerated Rule change process where the Rule changes are requested by SCER and arise from recommendations, agreed to by SCER, of an appropriately undertaken independent review, including previous AEMC reviews.
- SCER should reform its own processes and decision making so that critical NEM policy reviews, Rule changes and their implementation occur in a timely fashion.
- SCER should convert the current AEMC's review of reliability into an accelerated Rule change process to be completed by December 2013. SCER's Rule change request should draw on the Productivity Commission's recommendations.
- A merits review body should not be co-located with the AEMC.

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
- 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:

- the extent to which its prime charter is in the overall public interest
- to whom it is answerable, how it is funded, and its degree of independence
- how it is led, who selects and appoints its leaders and/or its board
- 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 plans, budgets and 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, external reviews and audit, and change.

In many respects, the central deficiency in the governance of the NEM is parochialism. Notwithstanding that the creation of the NEM was intended to create a *nationally* coherent energy market, state and territory governments have exercised control over critical areas important to the efficiency of the network. These areas have included: licensing arrangements; transmission planning; network reliability and safety; retail pricing and other features of the retail market; and in Queensland, New South Wales and Tasmania, ownership of the network businesses. At times, jurisdictional arrangements have not been in the interest of consumers, nor met other desirable principles of governance, such as transparency. This chapter does not address these governance issues directly, as the Commission has examined them separately in the preceding chapters. However, they are relevant to the future role of the Australian Energy Regulator (AER), as touched on below.

This chapter focuses on three areas of governance relating to electricity network regulation.

The governance of the Australian Energy Regulator and other institutions

The governance of the AER is an important issue. The Commission has made recommendations in this report that steer Australian regulatory arrangements away from the enduring parochialism discussed above. Such reform would substantially increase the regulatory responsibilities of the AER and change the way it deals with the businesses and consumers. However, several Australian governments and a variety of stakeholders in this inquiry have raised concerns about how the AER manages its current functions. This has implications for its capacity to perform in its new role, and may prejudice the willingness of the Standing Council on Energy and Resources (SCER) and the Council of Australian Governments (COAG) to move to a more national energy market in some key areas. Sections 21.1 and 21.2 explores these issues in depth. There are also grounds for periodic review of other bodies (section 21.3).

The role of the consumer

The goal of the NEM, expressed through the NEO is to promote efficient investment in, and efficient operation and use of, electricity services for the 'long term interests of consumers'. However, it is widely recognised that existing arrangements do not involve sufficient engagement with consumers (section 21.4).

Maximising the value of policy review

As observed in chapter 1, policy review in electricity is a busy space. A key question is how to maximise the value of such reviews, without having to repeat the process through the existing arrangements managed by the Australian Energy Market Commission (AEMC) and SCER. While those arrangements have many benefits, they can slow reform and duplicate analysis. Section 21.5 considers how to better manage the review and Rule making processes.

A related matter — addressed in section 21.6 — relates to what governance arrangements might be most appropriate for any new merits review body.

21.1 Governance and performance 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 the then *Trade Practices Act 1974* (now the *Competition and Consumer Act 2010).* It is funded by the Australian Government, with staff, facilities and other resources supplied by the Australian Competition and Consumer Commission (ACCC). The AER has three ‘members’ — two state and territory members (including the chair) nominated by SCER and a Commonwealth nominated member who is required to be an ACCC commissioner. The AER has permanent staffing of around 130 people, though there are around 10 ACCC staff working on AER matters (table 21.1).[1] Taking account of these, the AER accounts for nearly one-fifth of the total ACCC workforce (AER, pers. comm. 15 August 2012).

Table 21.1 **Staff numbers in the Australian Energy Regulator[a]**

Year	*Number of staff*
2007-08	83
2008-09	111
2009-10	112
2010-11	110
2011-12	129

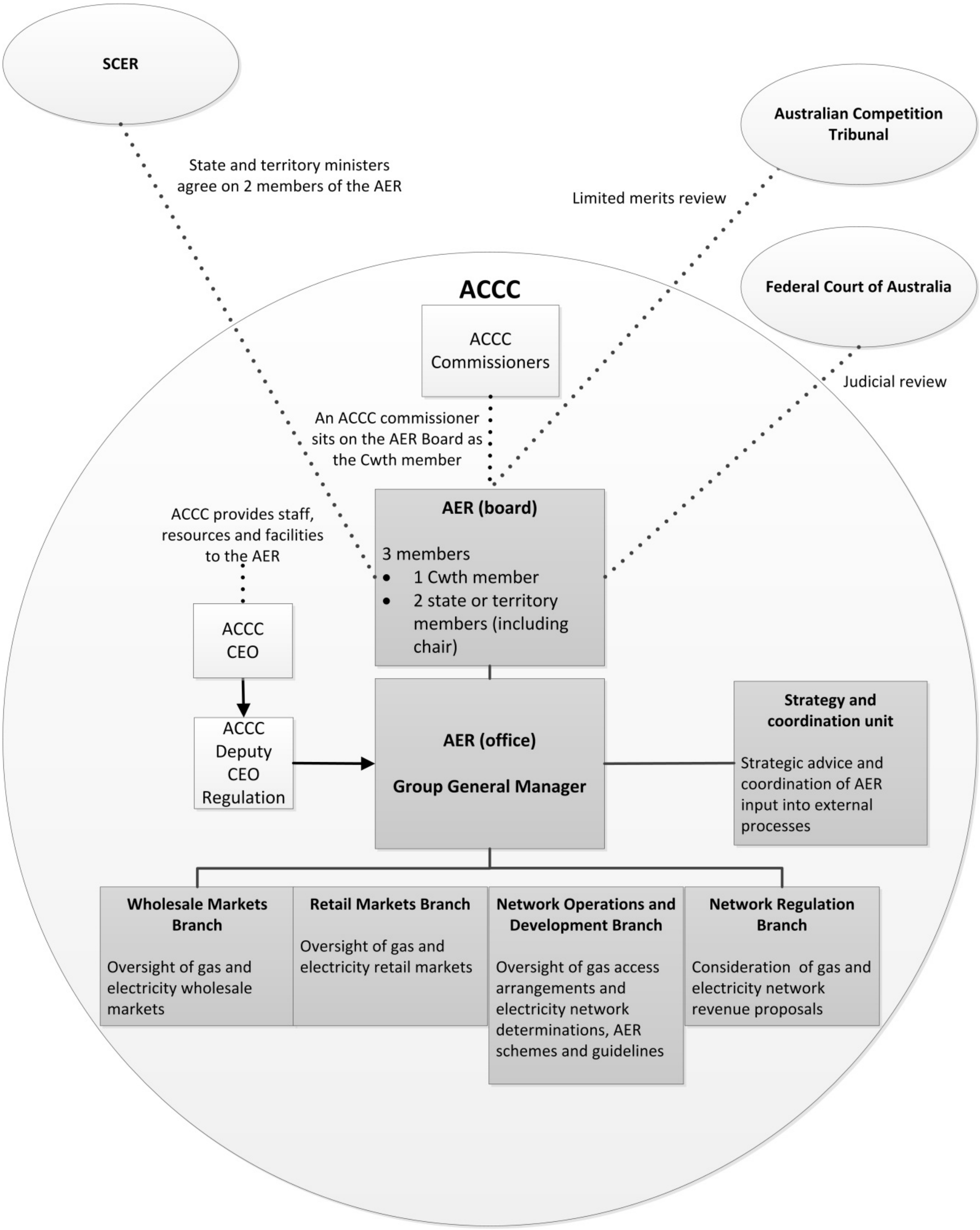
[a] As at 30 June.

Source: AER (sub. DR 104).

The structure of the AER — including its links with the ACCC, SCER, and two external review bodies — is set out in figure 21.1.

[1] The AER advised that other ACCC staff — such as legal, corporate and IT staff — spend some time working on AER matters.

Figure 21.1 **Structure of the Australian Energy Regulator**



Data sources: ACCC/AER (2011; 2012c); AER (2012k); SCER (2011b).

The AER's electricity network-related functions 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 concept of a national regulator had its origin in the Parer Review Panel, which proposed a coherent electricity market overseen by a single regulator. It envisioned:

> … a regulator … with strongly defined independence … and a national focus … established under a legislative approach agreed by all jurisdictions, accountable to these jurisdictions, with Commissioners appointed by the Ministerial Council on Energy and a charter that extends to the distribution and retail functions currently carried out by state and territory based regulators. (Parer et al. 2002, pp. 84-6)

The Panel's view was that 'the most appropriate approach' is for the national regulator to be 'a separate energy sector-specific agency' (Parer et al. 2002, pp. 13, 84, 86). However, as noted by the AER, the Panel considered that the location of the agency was less important than other aspects of its governance, indicating that its location was a matter for COAG (AER, sub. DR92, p. 23; Parer et al. 2002, p. 86).

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). The final model for the regulator also varied in other respects from the Parer Review Panel's proposal. Most notably, it had a narrower remit than intended and weaker accountability to the MCE.

Nevertheless, 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.

Areas of concern

Seven years on, participants in this inquiry and other commentators have raised concerns — some inter-linked — about the governance, performance and capabilities of the AER. In assessing these concerns, the Commission has drawn on several core principles, which it considers to apply to 'good governance' broadly defined (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 efficiently 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.

It is relatively easy to establish such principles, but harder to identify whether they are being effectively met. The Commission has assessed the AER's performance using several approaches. First, where possible, the Commission has used objective information in areas of contention, such as on staff turnover, budget reporting practices, and the degree to which governance structures match best practice. Second, it has used evidence on the perceptions of various stakeholders. Third, the Commission has had to make judgments in several areas — most particularly in relation to the desirable level of resourcing of the AER — a matter that has been recently addressed (see below).

Broad perceptions of the agency

Submissions to this and the Senate Select Committee on Electricity Prices, supplemented by the Commission's confidential consultations with all key stakeholders, provided mixed views about the performance of the national regulator (box 21.2). A similarly diverse picture emerged from stakeholder surveys commissioned by the AER (figure 21.2).

In particular, the AER's 2011 stakeholder survey found positive views in some critical areas. For example, 70 per cent rated the independence of the agency as good or excellent. Moreover, 73 per cent indicated that the AER was fulfilling its statutory role in protecting the long-term interests of Australian consumers with regard to the price, quality and reliability of energy services (Buchan 2011, p. 9). As this is the objective of the National Electricity Law, it is a key measure of its performance. Around the same share of respondents considered that the agency provided the right 'volume and sufficiency' of information.

Nevertheless, any agency can improve its performance. The (independent) Limited Merits Review Panel recently opined:

> 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)

The AER's 2011 stakeholder survey identified several apparent weaknesses, suggesting where efforts for improvement may be best directed. The share of respondents rating an attribute of the AER as good or excellent was only:

- 53 per cent for the AER's communication responsiveness[2]
- 43 per cent for the AER's output quality, 44 per cent for the agency's analytical and intellectual capacity and 40 per cent for technical competence
- 43 per cent for leadership
- 36 per cent for the AER's industry understanding.

2 Similar views about a lack of constructive engagement between the regulator and network service providers were expressed to the Limited Merits Review Panel (Yarrow et al. 2012c, p. 61).

Box 21.2 **Mixed views on the capabilities of the AER**

Some were positive. For example:

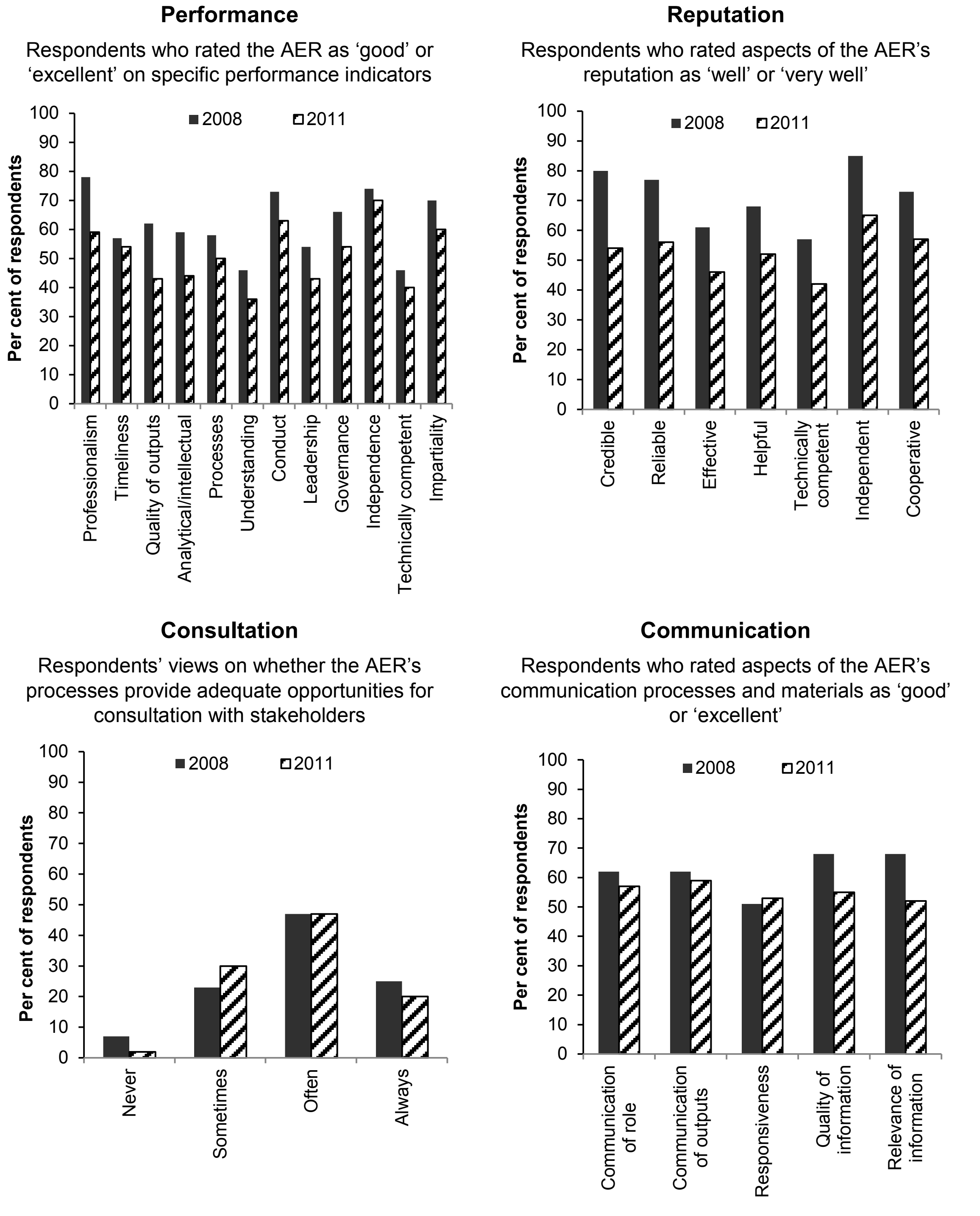
> … Overall, I think our experience of working with the AER is generally a positive one. We feel that we have ability to engage with them quite easily. [The AER] has its own customer consultative group, of which we're a member. They engage in numerous forums and opportunities for input during price examination processes. (Consumer Action Law Centre, trans., p. 87-9)
>
> … there are very good people there who have been hamstrung to a considerable extent by the rules. (Garnaut cited in SSCEP 2012, p. 76)
>
> [We have found] … AER staff to be highly capable and professional … there just are not enough of them and that they do not have enough power. (Total Environment Centre cited in SSCEP 2012, p. 76)

However, others perceived problems:

> The Businesses would welcome improvements to the AER's approach to communicate and engage constructively with industry, as this will assist AER staff in gaining a more thorough understanding of the electricity industry, how it operates and key factors influencing critical network investment decisions, and allow improved understanding of the specific characteristics of individual DNSPs and their respective customer groups. (CitiPower et al., sub. DR90, p. 15)
>
> … they need a greater level of resourcing of people who understand the business operations. … there's a limited extent to which you can use consultants to assist. … regulation has got too adversarial in Australia and … more understanding of the businesses' needs from both sides … would be better than the processes we have at the moment, where there's too much emphasis on the legal side … they need more strength of resourcing, independence, including engineering capability. (SP AusNet, trans., p. 37)
>
> 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. (Grid Australia 2012b, p. 39)
>
> [There is an] ongoing reported concern by ENA [Energy Networks Australia] members about a relative lack of stability and continuity within AER review teams even within the duration of a single review period of 12–24 months. Perhaps as a consequence of this, members have reported that relatively junior staff typically play a significant role in the initial stages of the AER's determination process, at times effectively 'pre-setting' some aspect of the AER's approach, and closing off alternative or more negotiated regulatory approaches. The AER does not appear to have an obvious central 'cadre' of specialists with detailed commercial industry background such as occurs in broadly equivalent regulatory bodies such as Ofgem in the UK. (ENA, sub. 40, p. 2)

In the Commission's confidential meetings, some participants said that the AER's determination process was 'combative and adversarial', and lacking in consultation, with frequent 'surprises' arising from determinations. Some claimed that the consultation process between United Kingdom distributors and Ofgem was better, as it involved significant ongoing contact.

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 Energy Customers Framework (retail law); and electricity and gas network regulation. The number of respondents in 2011 was 112 and in 2008 was 114.

Data source: Buchan (2011).

Of course, it is difficult to be certain what constitutes a good or bad outcome from any information based on the perceptions of stakeholders, some of whom must be aggrieved because decisions did not go their way or that have a 'vested' interest (Major Energy Users (MEU), sub. DR66, p. 9). The Commission is aware that other regulators also conduct stakeholder surveys. As the AER noted, as these develop, comparisons between the various surveys would be a useful benchmarking tool for the AER (sub. DR92, p. 20).

While such cross-regulator comparisons would be useful, so too would analysis of trend data for any individual regulator. For instance, stakeholders' positive views about the AER have declined since 2008 in relation to:

- 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 (figure 21.2).

On face value, these trends in the survey results are disturbing. However, some stakeholders considered that such survey evidence was of doubtful usefulness.

- Some argued that survey respondents would over-represent regulated businesses, which might have an axe to grind (Consumer Action Law Centre (CALC), sub. DR79, p. 6). However, while the survey did cover many stakeholders in the energy sector — including generation, gas and electricity distribution, and retailing — it was more diverse than this. Consumer groups, governments, regulators, ombudsman offices and ministers' offices accounted for around one third of the total of 112 respondents in the 2011 survey.
- Others noted that the survey was based on perceptions. This is correct, but inevitably, much of the information about the performance of a regulator must be based on the perceptions of various stakeholders. The AER observed that they were a snapshot of perceptions, and did not constitute a report card on the performance of the AER. In contrast, it indicated that the report of the Senate Select Committee on Electricity Prices gave a more balanced view on the performance of the AER, and that 'witnesses provided evidence that the AER has highly capable and professional staff' (sub. DR92, p. 20). However, the actual evidence presented to the Senate Select Committee related to the perceptions of just three participants, of which two indicated that the internal staff were of high quality. On face value, the AER's survey should have more

weight — given that it was conducted with confidentiality and with a sample size nearly 40 times greater than the number of Senate Select Committee witnesses cited by the AER. To some degree, the AER must have taken its survey results seriously as a measure of its own performance because it sought to make improvements based on them (sub. DR92, p. 19 and trans., p. 115ff).

- The context of the survey meant that it was likely to elicit negative comments. The AER indicated that the 2008 survey took place during a honeymoon period, while the 2011 survey was undertaken when the AER had completed distribution revenue resets and had assumed some responsibility for retail regulation (sub. DR92, p. 19).[3] Moreover, as pointed out by the AER, the merits review processes of the time were inherently adversarial, which could be expected to carry over to the qualitative impressions of the AER by the businesses concerned. Finally, as several participants commented, negative views about an agency's effectiveness can readily reflect constraints on the organisation, such as inadequate resourcing or a flawed regulatory environment (MEU, sub. DR66, p. 9; Total Environment Centre (TEC), sub. DR50, p. 7).

The last point seems particularly pertinent, and suggests care in interpreting the trend results in too negative a light. Nevertheless, the Commission considers that, at the time it was undertaken, the AER's 2011 stakeholder survey did identify several genuine concerns.

Resourcing and capacity

It is important that the AER has adequate resources and capacity (including appropriate in-house specialist expertise) to undertake its functions efficiently and effectively, including to apply rigorous analysis to its revenue and price determinations for network businesses.

As noted above, the Commission envisages a much broader role for the AER. Recent Rule changes also require the AER to develop guidelines in certain areas, and to produce annual benchmarking reports, presenting further challenges for the agency (AEMC 2012r). These add to the resourcing pressures stemming from a new set of network revenue determinations and the movement of retail regulation to the AER. While the evidence is incomplete, at least prima facie, it appears to the Commission that the AER may not have had sufficient funding in the past. There is

3 However, ENA (sub. 40, p. 4) suggested that the expected trend would be the other way, given that when the first survey was undertaken the AER was a relatively new agency, and likely to face teething problems. The survey consultants themselves were also more positive about the value of the comparisons between the 2008 and 2011 outcomes, and made no qualifications about their interpretation (Buchan 2011, p. 22).

an even more compelling case that the AER's existing resourcing and capacity would undermine its capacity to fulfil its future expanded role. The Senate Select Committee on Electricity Prices reached a similar conclusion (SSCEP 2012, p. 77).

Many stakeholders also identified resourcing problems in the AER both prior and after the Commission's draft report (box 21.3). Most supported a draft Commission recommendation about the need for adequate resourcing of the regulator.

Box 21.3 **Views on the resourcing of the Australian Energy Regulator**

> [The 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. (Energy Users Association of Australia, sub. 24, p. 10)
>
> … It is clear the AER does not have sufficient resources or powers to effectively play its full role in the NEM. The focus of the discussion should therefore be not on institutional reform, but on the needs of the AER as a regulatory body. These needs are likely to become greater given the range of proposals for reform in the NEM. For example, the [Productivity] Commission suggests that the AER maintain in-house expertise for the technical analysis required to undertake sophisticated benchmarking of network businesses, but the AER's capacity to do this at present is very limited. Likewise, initiating a public tender process for infrastructure projects would require more resources for the AER, but the costs would be more than offset by savings in the form of less infrastructure spending. (Total Environment Centre, sub. DR50, p. 7)
>
> We agree that more resourcing for the AER would be a good thing … (CALC, sub. DR79, p. 6)
>
> Enhanced resources is a pragmatic solution. (Alinta Energy, sub. DR81, p. 5)
>
> … We have said consistently that the AER would always welcome additional resources, as would any investigative agency … additional resourcing is an important factor. (AER, trans., p. 130)
>
> The [Senate Select Committee on Electricity Prices] shares the concerns raised about the adequacy of the AER's resourcing. The AER's resourcing — as it relates to the regulator's ability to effectively perform its role — should be the subject of ongoing consideration. The committee is also conscious that it, and others, have recommended expanded or additional powers for the regulator and therefore recommends that the AER should be allocated greater funding, expertise and accountability, particularly in light of any additional responsibilities it is given. (SSCEP 2012, p. 77).

In December 2012, the Australian Government announced that it would allocate an additional $23 million over four years to the AER's budget (Gillard 2012; table 21.2). This represents around a 20 per cent increase in funding above existing levels. However, over the subsequent three years, its funding is to decline in both nominal and real terms, which may affect its ability to plan for the long term. The adequacy of the AER's funding should be tested as part of the review proposed by the Commission (see below).

Table 21.2 **Funding available for the Australian Energy Regulator[a]**

Year	*Funding*
	$'000
2013-14	32 321
2014-15	30 492
2015-16	30 361

[a] Funding received by the ACCC for the AER is net of efficiency dividends and adjusted for parameter movements. Data include the further funding for the AER that was announced at December's COAG meeting.

Source: AER (sub. DR104).

There is equally a need to ensure adequate internal expertise and an appropriate mix of skills (Energy Supply Association of Australia, trans., pp. 176-7; Grid Australia 2012b, p. 39) — an area also highlighted by the survey results above. The AER indicated that it had responded to these concerns, saying that it had:

> … taken on board comments received in the 2011 survey, drawn on its experience and implemented a number of significant changes. It has acted on concerns about in-house technical expertise and employed more in-house technical experts. It has also put significant effort into improving engagement with network businesses. These efforts are bearing fruit with better engagement between the AER and network businesses. (sub. DR92, p. 19)

In responding to queries by the Commission, the AER (sub. DR92 and sub. DR104) also argued that some impressions about its staffing and expertise were not well founded.

- Staff have been recruited from other energy regulators (both state utility regulators and international energy regulators, such as Ofgem, consulting firms and the energy sector.
- The AER has staff exchange arrangements with other relevant agencies, such as the Australian Energy Market Operator (AEMO) and Ofgem.
- The AER is also involved in a range of international energy fora. The AER attends the World Forum on Energy Regulation and participates in the working groups under this forum. The AER hosts the website for the Energy Intermarket Surveillance Group and participates in all the Group's meetings.
- The AER disputed the claim that it faced 'internal competition' for high quality staff from other parts of the ACCC and experienced rapid staff turnover (a claim made by Energy Networks Australia (ENA), sub. 40, p. 2). The AER said that it is:

  > … seen as an attractive area to work, with internal and externally advertised vacancies attracting strong and competitive fields. While there is some movement from the AER into other areas of the ACCC, this turn-over is at a low level. (sub. DR92, p. 20)

Data provided by the AER to the Commission confirm that it has low labour turnover rates (table 21.3).

The Commission finds it difficult to reach any clear conclusion on the issue of staff capabilities in the AER. The AER has some good mechanisms in place to secure expertise, and its labour turnover rates suggest an organisation that is attractive to its employees. During the course of this inquiry, the Commission itself has routinely engaged with AER staff, and has learnt from their lengthy experience in the industry. However, since many industry parties (and others) have raised the issue of the adequacy of expertise in the AER, it would be useful if the proposed review (discussed below) examined this issue more closely.

Table 21.3 **Labour turnover in the Australian Energy Regulator**

Year	*Staff separations*	*Staff turnover*
	Number	%
2007-08	12	14.5
2008-09	9	8.1
2009-10	8	7.1
2010-11	10	9.1
2011-12	12	9.3

Source: AER (sub. DR104).

Errors

Participants, most notably ENA (sub. 40, p. 3), raised concerns about errors in the AER's decisions identified by the Australian Competition Tribunal ('the Tribunal') in its limited merits reviews.[4] AER decisions reviewable by the Tribunal include:

- revenue and price determinations for transmission and distribution in electricity (including the application of regulatory tests)
- decisions not to exempt entities from ring fencing guidelines or to impose additional ring fencing requirements in electricity.[5]

Most disputes have related to the weighted average cost of capital (WACC), and these have had the largest impact on revenue determinations (AER, sub. DR92, p. 21). There is little doubt that errors have been made. For example, in a case involving the *Application by EnergyAustralia and Others [2009] ACompT 8*, the

4 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.

5 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.

Tribunal found that ‘the AER exercised its discretion incorrectly, or its decision in this respect was unreasonable …’ (p. 32). However, the Tribunal has also found in favour of the AER in a range of other matters.

Errors are inescapable. The question is whether there are too many of them. ENA drew attention to the high count of errors in the case of the WACC. However, as the AER noted, some counts of errors relating to the WACC cover the same matter, leading to an upwardly biased measure of errors (sub. DR92, p. 21).

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 (Yarrow et. al. 2012b, annex 1). Applications to the Tribunal since 2008 appealed some 50 elements of decisions not involving WACC parameters. The AER conceded errors in five elements. The Tribunal found in favour of the AER in around 21 matters, with the remaining 25 elements varied by the Tribunal or remitted to the AER. On the face of it, outside the contested WACC issues, the AER and the businesses have rough parity in error making in matters brought to the Tribunal. It is hard, therefore, to assign lack of rigour to one party without doing so for the other.

In any case, some caution is needed in drawing strong conclusions about the degree to which raw counts of errors reveal much about the capabilities of the AER.

- 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 higher likelihood that the AER made an error, 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, the AER’s aggregate estimate may have been judged, at times, to be reasonable (which may be a better measure of error).
- Appeals concerning the WACC are likely to have arisen because of novel circumstances — first, the volatile credit market movements during the global financial crisis and, second, the first round of determinations by the AER under the new Rules.

A related issue is the degree to which the AER had sufficiently defended its position in appeal cases. There were two strands of concern in this area.

- The first was whether the AER had taken an overly narrow view of its status as a model litigant in defending its determinations before the Tribunal — a matter flagged by the Limited Merits Review Panel (Yarrow et. al. 2012b, p. 59, AER 2012l, pp. 7, 8). A requirement to be a model litigant does not appear to rule out the proper defence of a position (Lee 2006, p. 10).
- The second was the apparently paradoxical failure by the AER to use a provision in the National Electricity Law (s. 71O (1)) that would have allowed it to broaden the scope of an appeal, such that some appeal outcomes would have more favoured consumers.

However, on the former matter, the final report by the Limited Merits Review Panel did not make any clear finding — indicating that 'there was, to say the least, some confusion on these matters' (Yarrow et. al. 2012c, p. 47). On the latter, the answer is more definitive. On investigating the matter, the Acting Solicitor General agreed with the AER that it did not have such a power (ASG 2012). To the extent there is a fault in this area, it lies with the National Electricity Law and Regulations, and not with the AER.

The issue of 'independence'

In addition to the above (contested) concerns about how the ACCC has affected the AER's resourcing and capacity, some parties expressed concern about the independence of the AER. The word 'independence' means different things to different people, and is worth clarifying. The context in which most parties have used it in this inquiry is the independence of the AER from the ACCC, and not between the AER and government and business. For example, the Limited Merits Review Panel heard views that:

> … the AER Chair and members are constrained in their ability to independently direct the development and utilisation of the organisational expertise and capabilities that are required for the effective performance of its role. The relevant points ranged from practical, administrative points such as limitations on the ability to direct organisational strategy and performance and to recruit and retain suitably qualified staff, to more fundamental issues such as the difficulties of reconciling a culture of 'continuous engagement' with stakeholders of the kind associated with contemporary utility regulation with the necessarily more arm's length culture that is appropriate to an enforcement agency such as the ACCC. (Yarrow et al. 2012c, p. 61)

While actually repudiating any substantive issue, the inaugural chair of the AER, Edwell, also framed independence in terms of the relationship between the AER and the ACCC. He observed 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. (2005, p. 5)

Whatever the *actual* circumstance, the fact that the two bodies are co-located, share staff, and have no separate annual report and budgets might reduce stakeholders' confidence that the de jure provision for independence was in fact being fully realised. In that vein, the AER's contention that the Commission's 'discussion of the AER's independence overlooks the fundamental point that the AER is established as an independent regulatory authority' (sub. DR92, p. 22) misses this important distinction. The distinction is not lost on state and territory governments, some of whom have publicly called for structural separation (Department of Primary Industries (Vic), sub. DR94, pp. 13ff). A recent SCER report to COAG noted:

> … Some Ministers expressed concern that the existing structure of the AER within the Australian Competition and Consumer Commission … could limit the regulator's ability to effectively perform its operations and considered that structural separation could be considered by the Council of Australian Governments … . (SCER 2012b, p. 1)

As noted above, the creation of an entirely separate entity is consistent with the findings of the Parer Review Panel (and the MCE proposed industry funding of such a regulator in 2003). The Limited Merits Review Panel recently recommended that the 'issue of the AER's independence from the ACCC be revisited' (Yarrow et al. 2012c, p. 61). On the other hand, some other participants have questioned whether the issue is relevant (TEC, sub. DR50, p. 7).[6]

The Commission assesses the desirability of re-structuring the AER later in this chapter.

21.2 Reform of Australian Energy Regulator governance

The immediate way forward

The AER is aware of some of the areas of concern about resourcing, capacity and consultation — and appears to be taking measures to address them (SSCEP 2012, p. 77; AER, sub. DR92, p. 19). As noted above, the Australian Government has provided additional funding, while COAG (2012, pp. 1-2) has also recognised some

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6 Opposition was mainly from parties that represent consumer interests (for example, CALC, sub. DR79, p. 6; MEU, sub. DR66, pp. 9-10; and PIAC, sub. DR65, pp. 25-6.)

of the concerns about governance identified above. COAG announced a reform package, which included:

- budget transparency for the AER, including the allocation of program funds over the previous financial year, and information on projected AER funding and staffing (separately from that of the ACCC) over the forward estimates period
- the conversion to full-time status of the currently part-time state-nominated AER board member (with the chairman and the other board member already being full time)
- a regular public report by the AER on its activities, including its budget and business plan, its performance against key performance indicators, and its views on emerging regulatory issues
- an independent review by the Australian Government of the AER and its operational requirements initiated in July 2014 to ensure that its resourcing is adequate and its operational arrangements are effective.

The Commission recommended many of these reforms in its draft report, such as greater transparency and a focused review,[7] and so does not reiterate the desirability of these broad reforms. Nevertheless, several observations can be made about some of the details of such reforms not touched upon by COAG. In relation to reforms of its governance, the AER should:

- submit a separate annual report from that of the ACCC, and not just separate reporting in a joint ACCC/AER annual report
- have 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 will likely require negotiating separate service level agreements with the ACCC for corporate services and other 'overheads', with the specification of charges, levels of service and expected performance. Given the greater need for benchmarking (and the associated reporting of these results), it will be important that the AER establishes and retains the necessary specialist expertise to competently carry out its role, in accordance with recommendation 8.6
- publicly reveal its strategies for improving its performance, including how it intends to address concerns from stakeholders that become apparent from

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7 Many participants in this inquiry supported such a review. For example, the Department of Primary Industries (Vic) (trans., p. 277); ENA (sub. DR71, attachment A, p. 19); MEU (trans., p. 182); National Seniors (sub. DR62, p. 17); the NSW Distribution Network Service Providers (sub. DR85, p. 4); PIAC (sub. DR65, p. 26). CALC (sub. DR79, p. 7) considered that any such review should be scheduled at a later date as part of a general review of the effectiveness of reforms.

various stakeholder surveys. This includes providing milestones against which to assess whether the strategy is working. Given comments from various parties, a critical element of this will be regular ongoing communication and interaction with network businesses, their customers and other relevant stakeholders

- be able (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 AEMO and the AEMC, as well as state and territory utility regulators such as the New South Wales Independent Pricing and Regulatory Tribunal (IPART) and the Victorian Essential Services Commission (ESC)
- 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.

RECOMMENDATION 21.1

The Australian Energy Regulator should have greater control over, and accountability for, the resourcing and management of its functions. It should:

- ***submit a separate annual report of its performance***
- ***have administrative control over its own budget, which would need to be adequate for it to manage its functions efficiently and effectively, including acquiring, developing and retaining the necessary specialist expertise***
- ***publicly reveal its strategies for addressing current stakeholder concerns and those raised in future stakeholder surveys***
- ***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 strengthens and retains the necessary specialist expertise to competently carry out its role, in accordance with 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.***

In relation to the 2014 review of the AER announced by SCER, in the Commission's view, it:

- 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 would be important. The panel reviewing the limited merits review regime exemplifies this model

- should include consideration of the remuneration conditions offered by the AER (particularly, compared with the AEMC) to attract and retain the specialist expertise necessary to perform its role
- could involve the commissioning of an independent stakeholder survey (as a substitute for the ones previously commissioned by the AER)
- should include consideration of funding options for the agency.

RECOMMENDATION 21.2

The 2014 independent review of the resourcing and capacity of the Australian Energy Regulator (AER) should be undertaken by a small group of senior and experienced persons.

- ***These persons should be external to the Australian Competition and Consumer Commission and the AER, have an appropriate understanding of the competencies required to undertake utility regulation, and include some contemporary international experience from counterpart regulators.***

The review should, among its other tasks:

- ***specifically address any difficulties the AER has in attracting and retaining specialist staff***
- ***consider the commissioning of an independent stakeholder survey covering the relevant review issues***
- ***consider funding options for the AER.***

Longer-run governance issues

Structural change?

There are many possible structural configurations of the AER. In the Commission's discussions, three broad options for change emerged, which involved:

- integrating the AER completely within the ACCC and abandoning a separate specialist energy regulator
- combining the AER and the AEMC
- separating the AER from the ACCC.

However, the first option would hardly address the concerns about adequate independence of the AER from the ACCC and, accordingly, could frustrate a shift to a more NEM-wide regulatory model.

In principle, the second option 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 2011b, p. 5). However, this option also raises potential conflicts of interest for the rule makers in the merged agency. For instance, 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. Concerns about coordination and overlap in the activities of the AEMC and the AER might be better addressed under the 2009 Memorandum of Understanding between the ACCC, the AEMC and the AER.

Several stakeholders have raised the third option. While the COAG implementation plan for energy reform does not include any proposal for separation of the AER from the ACCC, it suggests that the issue of the structure of the AER remains open (COAG 2012, p. 2).

Were separation to occur, the AER would be reconstituted as an independent and separate national regulator with appropriate governance arrangements (that met the principles in box 21.1) and a budget that allowed it adequate scope to have access to satisfactory levels of internal and external specialist expertise. Implementation could occur by:

- enacting new South Australian legislation akin to the *Australian Energy Market Commission Establishment Act 2004*, or
- amending the *Competition and Consumer Act 2010*, which currently establishes the AER.

The AER could, where appropriate, negotiate arrangements with the ACCC, the AEMC, AEMO and other relevant organisations to share resources such as: offices; payroll services; information and communications technology services; and professional staff.

This option would involve carefully weighing a range of tradeoffs.

The advantages of retaining the AER within the ACCC

On the one hand, the current arrangement of retaining the AER within the ACCC has the following advantages.

- Their proximity and sharing of some resources may encourage a more 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 (AER, sub. DR92, p. 23).[8] 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 IPART and the ESC) 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. The Commission understands that if the regulator had to handle these tasks on a stand-alone basis, the AER might need more staff with lower average utilisation. Although there are clear benefits from resource sharing, 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.

- There would appear to be real synergies between the two organisations, a point emphasised by the CALC (sub. DR79, p. 6). 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 WACC and benchmarking technical matters from a special ACCC-wide analytical branch.

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8 The AER (sub. DR92, p. 22) also noted the conclusion of the Hilmer Review that 'there are sufficient common features between access issues in the key network industries to administer them through a common body.' The AER did not go so far as to say that the AER and the ACCC should be merged, but saw the existing model as a satisfactory hybrid between the Parer and Hilmer models.

However, were the AER to be separated from the ACCC, some of the current synergies with the ACCC could be retained. For example, the AER could still 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 risk that an industry-specific regulator may identify too closely with the interests of the industry ('regulatory capture') — an observation also made by CALC (sub. DR79, p. 7). The Limited Merits Review Panel extended this to political capture as follows:

  > … what may be the strongest argument for the ACCC connection [is] namely the protection of regulatory decision making processes from pressures to be inappropriately swayed by the agendas of influential parties, including by what may be the fluctuating priorities of the government of the day. (Yarrow et al. 2012c, p. 61)

  However, the Limited Merits Review Panel noted that the 'current ACCC connection does not appear to have prevented the AER, in the recent period, from making statements about electricity prices that are quite political in nature' (Yarrow et al. 2012c, p. 62).

  Even as a stand-alone entity, risks of capture 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 energy retailing (through the adoption of the National Energy Customer Framework).

- Further mechanisms to reduce the risks of capture include:
  - the creation of a consumer body, which would be expected to be active in the AER's regulatory processes (see below)
  - an AER with appropriate governance, such as an appropriately constituted board
  - secondments and exchanges of AER senior managers with counterpart international regulators
  - transparent reporting and periodic review of the AER
  - a 'fully investigative review process' as proposed by the Limited Merits Review Panel (Yarrow et al. 2012c, p. 62).

- 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 enacting or amending legislation, developing a new organisational structure, making staff appointments, and establishing payroll and information technology systems. Any structural separation would risk disrupting complex regulatory determinations already in play. Also, the Australian Government is concerned about the proliferation of small agencies, and has previously taken measures to reduce their number.

The advantages of separation

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 enduring natural monopoly status of electricity networks, than some other forms of infrastructure, such as telecommunications. Thus, 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)

  Biggar (2011b) 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 … 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. (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 deceptive 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. The Limited Merits Review Panel similarly observed recently:

> … A significant part of the incentive effects of regulation derive from the existence of an ongoing relationship between the regulator and the NSPs [network service providers]. For example, the longer-term relationship should, if it functions correctly, serve to discourage opportunism on both sides, and, since a vulnerability to opportunism is one of the weaknesses identified by the Panel in relation to the operation of the existing LMR [limited merits review] regime, this may be an important consideration when thinking about issues of institutional design. (Yarrow et al. 2012c, p. 61)

As noted earlier, participants have already expressed concerns about the allegedly combative approach of the AER and the lack of consultation.

- Separation would resolve any perceptions (well-founded or not) that there were conflicts of interests between the AER and the ACCC.

The Commission's view

There are clearly arguments for and against creating an energy regulator entirely separated from the ACCC. On balance, the Commission's judgment is that the status quo should be maintained. The decisive factor is that the change would be costly and disruptive, and would underplay the capacity of less ambitious reforms to improve the AER's governance. In particular, more resourcing, and improved transparency and accountability should shore up trust in the agency, without the significant transactions costs of full structural separation. However, a follow-up independent review in 2018 should examine whether the measures outlined in recommendation 21.1 have achieved their goals, and if not, re-consider the structural issues.

RECOMMENDATION 21.3

The Australian Energy Regulator (AER) should remain located within the Australian Competition and Consumer Commission (ACCC). However, a follow-up independent review should be carried out in 2018 to examine if the reforms to the AER's resourcing and transparency (recommendation 21.1) have had the desired impacts. If not, the issue of the AER's structural separation from the ACCC should be examined together with other possible changes to improve its performance.

Funding through an industry (or National Electricity Market) levy

Currently, the Australian Government takes entire responsibility for funding the AER. Some saw another source of income as potentially useful:

> PIAC [The Public Interest Advocacy Centre] accepts that an industry levy may need to form part of the AER's funding base, particularly if a review of resourcing identifies the need for a dramatic increase in AER resources. However, … it would be important that the AER's source of income not compromise its independence. (sub. DR65, p. 26)

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.

While alternative funding models would become immediately relevant were the AER to be entirely separated from the ACCC, the potential for an industry or some other kind of shared funding arrangement might still be applicable even were the AER to remain within the ACCC.

Several Australian utility regulators — such as the ESC, IPART, 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'[9] 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 sector, there are 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). The National Offshore Petroleum Safety and Environmental Management Authority is fully funded from the 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.

9 The 'national regulatory cost' relates to the ACT Government's obligations under the Australian Energy Market Agreement to contribute to funding the AEMC and SCER.

- 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 might allow the regulator to have a remuneration policy that is more consistent with the needs of being able to attract and retain the necessary specialist expertise required to fulfil the AER's role (to the extent that this is a well-founded issue).
- 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 the regulation of national energy markets.
- The regulator would be better able to plan for an adequate and efficient level of resources, rather than being subject to global efficiency dividends or other short-term Australian Government budget stringencies.

However, there are potential concerns about an industry levy, such as impressions of industry capture, the legislative challenges of giving it effect, and the considerable complexities in gathering funding from the multiple jurisdictions in the NEM.

Given that the Australian Government has announced significant new funding, the Commission does not see grounds at this stage for a change in the funding model. As discussed earlier, funding options should be considered as part of the 2014 review.

21.3 What about AEMO, the AEMC and other NEM bodies?

Few parties have suggested that the governance arrangements for AEMO and the AEMC should be altered radically. However, the MEU and Visy argued that there were benefits from reviewing all aspects of the institutional arrangements.

> In addition, the MEU considers that the performance of the key NEM institutions, including importantly the AEMC, require independent review to ensure proper resourcing and quality performance. This will follow the recent review of the limited merits review regime and the AER … (MEU, sub. DR66, p. 6)
>
> … There must be a review of the AEMC, the institution responsible (more than any other NEM institution) in compromising Australia's hitherto strategic competitive advantage in electricity pricing since 2007. … The AEMC must be made to be more accountable for its actions and be more cognisant of consumer interests and issues. Its performance to date has been found wanting. (Visy, sub. DR98, p. 2)

The fundamental point made by the MEU is sound and is consistent with the view articulated by the Australian Government in its 2012 Energy White Paper (DRET 2012b, p. 171). The key (non-political actors in the NEM) are the merits appeal body, the AER, the AEMC and AEMO. The first (the Australian Competition Tribunal) has recently been reviewed, and the second will be shortly. There are grounds for independent reviews of the other two agencies to identify any potential for improvement.

Such reviews do not need to occur immediately, but should be undertaken within the next five years. Moreover, the National Energy Consumer Advocacy Body proposed by SCER should be subject to review after some years of operation. Reviews should occur for all institutions in the NEM (including the AER), preferably, at 10 year intervals after 2018.

Along with identifying potential for improvement, the reviews should consider resourcing and capacity issues.

RECOMMENDATION 21.4

The operation and performance of the Australian Energy Market Commission, the Australian Energy Market Operator and the proposed new National Energy Consumer Advocacy Body should be independently reviewed by 2018 to identify opportunities for improvements. All these institutions and the Australian Energy Regulator should be reviewed at least at 10 year intervals after that time.

21.4 Consumer engagement and representation

The NEO refers expressly to the 'long term interests of consumers', and yet until recent reforms (listed below), the role of consumers in regulatory outcomes had been weak.

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' covers 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.[10]

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 nine 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 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 provides grants[11] for consumer advocacy and research for the benefits of consumers of electricity or natural gas (AEMC 2011j, k). The 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 2011-12, the Consumer Advocacy Panel allocated funding for grants totalling around \$2.5 million, which included around \$1.6 million for electricity advocacy and \$29 000 for panel-initiated electricity research (AEMC 2011j, pp. 98-9).[12] Most groups received relatively small grants — often for narrowly-defined projects.

Despite these mechanisms, there is widespread dissatisfaction with consumer engagement in electricity network regulation (box 21.4), and a view that, regulators in other countries engage with consumers or consumer representatives more than the AER (AEMC 2012r, p. 100).

[10] However, consumer groups had told the Limited Merits Review Panel of their 'attempts' to get their 'voices heard' at Tribunal hearings (Yarrow et al. 2012b, p. 43), suggesting that their participation in Tribunal hearings has not been effective.

[11] The Consumer Advocacy Panel can award grants for specific projects as well as 'global advocacy funding grants' — where one grant supports a range of nominated priority projects nominated by the recipient — and 'capacity-building grants' — which are used for advocacy and to build capacity in a recipient to facilitate its advocacy activities.

[12] The total funding also includes grants for gas advocacy and research, as well as for joint electricity and gas advocacy and research.

Box 21.4 **Consumers have a weak voice in electricity network regulation**

Mountain (who often represents the Energy Users Association of Australia) noted the disempowerment of users in regulatory reviews:

> … 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. (2012b, p. 23)

The Limited Merits Review Panel said that consumers were seen as 'inconvenient guests' in the merits review process (Yarrow et al. 2012b, p. 44). The Panel also noted that network service providers themselves recognised weaknesses in their relationships with consumers and major energy users (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]. Whilst 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. (Yarrow et al. 2012b, p. 67)

In a report for ENA, Fels (2012, p. 80) observed that funding through the Consumer Advocacy Panel was 'derisory', the benefits of funding were too dispersed among groups to make a difference, the focus of consumer groups was too narrow, and an attention to state-based matters undermined a NEM-wide perspective.

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 or subjects; insufficient resources and funding; insufficient skills or access to the right technical expertise; failure by decision makers to consult adequately; and a lack of attention given to the overall regulatory framework (pp. 46-7).

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 under-developed. 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)

New policies for consumer engagement

In late 2012, Australian governments announced several measures to encourage greater consumer engagement including the following.

- The creation by the Australian Government of a Consumer Challenge Panel comprising industry experts and located in the AER, with its goal to represent consumers' interests in regulatory determinations (Gillard 2012 and COAG 2012). The AER has announced it will establish the Panel by 1 July 2013 (AER 2013b).
- By the end of 2013, SCER will create a National Energy Consumer Advocacy Body to contribute to energy policy development, Rule change processes, and network determinations (including appropriate appeals processes). SCER will develop the funding, form and scope of the new body in consultation with consumer groups. The new body will be 'equipped to engage in regulatory processes, support targeted research and advocacy initiatives, and lead on national advocacy issues' (COAG 2012, p. 6; SCER 2013a).
  - In January 2013, SCER announced a review of the objectives of the new body, its governance funding models and relationships with other advocacy arrangements (Tamblyn and Ryan 2013, pp. 3, 5) to be completed by 30 April 2013 (SCER 2013a). The Productivity Commission supports the scope and process of this review. As outlined below, it has examined some of the key issues, which hopefully will contribute to the review's findings.[13]
  - As the establishment of the new body is likely to require legislative change, and so could not be implemented immediately, SCER has indicated that some immediate steps will be taken to improve consumer representation in the energy market (though these were not specified).
- By June 2013, SCER will develop improved criteria for grants made by the Consumer Advocacy Panel, so that the grants have a greater focus on addressing priority needs of average energy consumers, 'including in AEMC processes'

[13] The Commission has not considered more ambitious consumer representation models — such as a national body representing consumers across multiple utility and other sectors. This is the approach taken in some other countries, such as Consumer Focus in the United Kingdom. In California there is 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 *all* utilities, and not just those in the energy sector (Mountain 2012b, p. 28). The Commission (PC 2008) recommended the creation of a representative national peak body for all relevant consumer issues in its inquiry into consumer policy (which the Australian Government did not adopt). While there are some advantages to a more holistic approach to consumer representation, it is highly unlikely that this would gain traction in Australia, given governments have already committed to certain policy measures and that radical re-configuration of these would not be practical over the shorter run.

(COAG 2012, p. 6). SCER will consider the appropriate mechanism and location of the function for the allocation of consumer grants, given the creation of the other two institutions above.

- The AEMC (2012r, p. 7, pp. 35ff, and pp. 148, 180) has made Rule changes that mandate certain types of consumer engagement. The AER is required to provide an issues paper accessible to consumers about a network business's proposal and to hold a public forum. Network service providers are also required to provide a plain language overview that explains how it has engaged with consumers and that outlines its revenue proposal. The AER has the power to require re-submission of the paper if it were not adequate. When determining the capital expenditure and operating expenditure allowances of a business, the AER is also required to take into account the extent to which the network service provider had engaged with consumers in preparing its forecasts.

The proposals are generally consistent with the views of many parties (including the Commission in its draft report) that a more coherent model for consumer engagement in energy policy and regulation, including a national representative body, was required.[14]

Detailed models have been proposed by some parties, including participants in the Commission's inquiry. For example, CALC (sub. DR79), the TEC (sub. DR50) and the Public Interest Advocacy Centre (PIAC, sub. DR 65) proposed a new national advocacy body called Energy Consumers Australia. However, their proposed body would not be broadly representative of all energy consumers. It would focus on residential consumers and small business consumers, particularly those who are vulnerable. Further, it appears that the proposed body would not exclusively focus its attention on the achievement of the NEO. Instead, it would appear, from its stated objectives, that there is a risk it might give undue weight to additional goals such as social and environmental objectives that could give rise to conflicts with the NEO.

The role of the Consumer Advocacy Panel and research grants

It is legitimate to provide grants for some research and associated advocacy, recognising that coordinated action by the large number of households and small

[14] While there were differences in views about the design and scope of any bodies, there was support for a national advocacy body from Fels (2012, p. 81); CHOICE and ACOSS (as cited in SSCEP 2012, pp. 134-5); and the Senate Select Committee on Electricity Prices (SSCEP 2012, p. 135). A diverse group of participants in this inquiry also supported some kind of formal representation (including the AEMC, sub. DR89; the AER, sub. DR92; AGL, sub. DR86; CALC, sub. DR79; EnergyAustralia, sub. DR82; the NSW Distribution Network Service Providers, sub. DR85; TEC, sub. DR50).

businesses to engage in research or advocacy on consumer issues is not likely to occur. In any case, such activities are most valuable when consumers have an effective conduit to affect regulatory processes and policy, which is also clearly lacking. To that extent, there is a strong rationale for the role performed by the existing Consumer Advocacy Panel.

However, there is little rationale for the existence of the Panel as a separate entity. There are likely to be economies of scope and scale in incorporating the grant function into the National Energy Consumer Advocacy Body. (This would also recognise the increasing antipathy by governments to the proliferation of many small agencies.) The latter would have the expertise to determine the research and associated advocacy projects most likely to further the interests of consumers, and to have the knowledge to make merit-based choices among competing grant applications. There are also grounds for the new body to directly commission research relevant to its objectives, but with a quota on the share of funds that it can use this way. The implication is that the existing Consumer Advocacy Panel should be wound up when the National Energy Consumer Advocacy Body is created. While there was some support for the removal of the Consumer Advocacy Panel, such as by the NSW Distribution Network Service Providers (sub. DR85, attachment A, p. 8), others were concerned that its removal might threaten funding of existing advocacy groups (for example, CALC, sub. DR79, p. 2). The Commission considers that the appropriate budget for funding of advocacy and research external to the National Energy Consumer Advocacy Body is a separate issue. There is already some process for determining the budget of the Consumer Advocacy Panel and a similar (if not more rigorous) process could be used to determine the *external* grant budget of the National Energy Consumer Advocacy Body.

There is also little rationale for providing grants to groups that would be likely to undertake research and advocacy in the absence of subsidies. It is notable that the two peak bodies representing major users (the Energy Users Association of Australia and MEU) received around 18 per cent of the Consumer Advocacy Panel funding for 2011-12.[15] Unlike the bulk of other consumer groups receiving funding from the Consumer Advocacy Panel, these bodies represent relatively few electricity customers, which also command large resources. It seems likely that without eligibility for grants, these groups would continue to exist and to champion the interests of their constituents. While there should be no blanket ban on grants to any given group, the grant panel of the National Energy Consumer Advocacy Body should only provide grants where it is reasonably satisfied that the grants fund activities that are important and would not otherwise occur. These activities cover

[15] Funding was provided through a global advocacy funding grant for 2011-12.

research and the associated capacity to make informed submissions to reviews, appeals and determinations so that individual groups can represent their constituencies. Funding should be provided on a contestable basis.

The National Energy Consumer Advocacy Body

Functions and governance

SCER's proposed objectives and activities for the National Energy Consumer Advocacy Body (SCER 2013c, p. 2) would address the main deficiencies in the current arrangements, though these functions should be expanded to include the provision of grants and a capacity for reaching negotiated settlements with the network businesses (chapter 8).

However, as currently specified there appears to be a major overlap between the Australian Government-funded Consumer Challenge Panel and the National Energy Consumer Advocacy Body. Both are to be involved in network determinations. It is hard to see how the two bodies would interact in undertaking their roles without wasteful duplication, especially since it is not clear that they would, or should, have significantly different constituencies. An alternative would be for the Consumer Challenge Panel to be part of the National Energy Consumer Advocacy Body. It would be a secondary issue whether the Australian Government were to fund this part of the body. However, the National Energy Consumer Advocacy Body should be independent from the regulator. This reflects the desirability that the AER be seen as a neutral player. It would also recognise that the National Energy Consumer Advocacy Body would be acting in its own right at merits reviews, in any negotiated settlements, in Rule change requests, and submissions to AEMC reviews, and might sometimes want to adopt positions contrary to that of the AER. The independence of the National Energy Consumer Advocacy Body would not preclude it from having ongoing communication about technical and procedural issues with the AER (and indeed with the AEMC and AEMO).

Nevertheless, it will be some time before the National Energy Consumer Advocacy Body is created. An advantage of the Consumer Challenge Panel is that it is planned to be operational by mid-2013 and thus has the potential to make an immediate impact in the regulatory process. Accordingly, there are grounds for a separate Consumer Challenge Panel in the shorter run.

The implication of the above is that ultimately there should be a single national consumer body with a focus (initially at least) on energy policy and regulation, rather than three overlapping national bodies.

To act effectively, the role and associated skill set of the National Energy Consumer Advocacy Body would have to go beyond the current focus of many consumer groups on affordability issues (though these remain important). Thus, the body should have strong expertise in economic regulation in energy markets and competence in the relevant engineering areas.

The governance arrangements of the body should reflect its broad role and the necessity for the body to genuinely represent consumers as a whole, and not particular constituencies (such as vulnerable consumers alone). This can be achieved through the appointment of an expertise-based board, 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 National Energy Consumer Advocacy Body should be financed through a small ongoing levy on market participants (effectively amounting to a consumer levy). This would provide greater certainty, and independence, of funding than annual government budget appropriations. However, were the body to be funded by government, there should be commitment to a long-term (such as a rolling five year) budget.

Who should the National Energy Consumer Advocacy Body represent?

The Commission considers that the key function of such a body would be to represent the interests of *all* energy consumers (for example, households, businesses and major industry users) during policy, regulatory, rule-making and limited merits review processes (such as an AER regulatory determination process).

The fact that large energy users have ‘deep pockets’ (TEC, sub. DR50, p. 3) is relevant to their eligibility for grants, but not for their representation in the National Energy Consumer Advocacy Body. In fact, bringing them to the table carries with it the benefits of highly sophisticated and demanding customers, adding to the negotiating grunt and authority of the body. Once there are carve outs of particular groups, there is a risk that the remaining body would become a creature of sectional interests, which would not assist its credibility or effectiveness.

Moreover, on many issues, consumers have common concerns — they would like high quality services at sustainably efficient prices. It is notable that the MEU and the Energy Users Association of Australia have championed changes to the Rules that would produce benefits for all consumers. There is no reason why some issues important to some consumers — such as hardship policies — should be neglected in this model. The inclusion of an advisory group in the governance structure would ensure that all consumer voices were heard. The National Energy Consumer

Advocacy Body could develop competencies in disparate areas — such as smart meters, critical peak pricing, reliability and policies for vulnerable consumers.

Nevertheless, the Commission agrees that there will be tensions between the interests and enthusiasms of disparate consumer groups on some matters. While these may lead to robust but healthy debates within the National Energy Consumer Advocacy Body, they could, if not managed carefully, undermine the effectiveness of the body. For example, the MEU said:

> Certainly, consumer advocates with an environmental bias have quite clearly enunciated differing views to large and small businesses in a number of key aspects, although they have common views in other areas. (sub. DR66, p. 11)

However, there are two rejoinders to these concerns.

- The National Energy Consumer Advocacy Body should not be the only outlet for consumer advocacy. It should not preclude the involvement of other consumer groups in regulatory and policy processes — such as in merits 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.[16] That, if achieved, should increase the options for participation by many consumer groups. (As noted above, some of these could access the grants provided by the body.)
- It is not clear that any such 'national' body could function well if it did not compromise. For example, households are not homogenous. People with air conditioners might well prefer to prevent critical peak pricing, while others would rather stop cross-subsidising them. An important aspect of an effective National Energy Consumer Advocacy Body will be that it concentrates on the NEO as its underpinning principle, and not the interests of particular consumer groups that are contrary to the long-term interests of most consumers. As noted by GDF Suez Energy Australia (sub. DR68, p. 4), a focus on the long term is important to avoid the 'temptation for customer groups and political interests to focus on short-term gains'. Notably, among all customer groups, industrial customers with long-lived energy-intensive assets must recognise that there is a tradeoff between low prices now and reliable long-run electricity supply. This provides another benefit of the involvement of large users in the national body.

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16 The Limited Merits Review Panel expressed some concern about representation of one consumer agent in the merits review process (Yarrow et. al 2012c, p. 60), arguing for the benefits of a variety of consumer perspectives. This is consistent with the Commission's proposed arrangement since the national advisory body would not have exclusive access to the merits review process, and other groups would continue to be funded.

A national consumer body is an experiment. It appears to have functioned well enough in other countries, but the outcomes will depend crucially on its governance, and the design of the regulatory arrangements that give it a capacity for influence. As in any other major institutions, its effectiveness should be evaluated after a suitable period (recommendation 21.4).

The initial focus on energy might extend to water

The initial energy policy and regulation focus of the national consumer advocacy body could also be extended to water. 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 obligations to engage

As described earlier, the AEMC has introduced Rule changes that mandate certain engagement arrangements. Some, such as the obligation for the AER to produce an issues paper and for networks to provide an overview of their proposals, do not appear costly and may assist consumers to some extent. However, some other aspects of the Rule changes *may* have unintended consequences.

- A requirement for businesses to detail their engagement with consumers in their overview document might risk a 'compliance' mentality. It is hard to differentiate engagement in good faith from engagement due to a statutory requirement — thus, undermining the goal of the Rule change.
- Hinging any amount of the revenue determination on the AER's judgment about the seriousness of a network business's engagement with consumers on forecasts would involve many subjective judgments and might risk arbitrary decisions.

The AEMC has only recently determined these Rules, so their actual effects are as yet unknown. They may actually prove useful, or at worst innocuous. However, given the risks of unintended consequences, the AEMC and the AER should monitor their usefulness during the current determination processes.

However, an unresolved question is whether these kinds of Rules should have been made in the first place. It might have been better to have assessed whether encouragement by the AER for network businesses to voluntarily engage more with consumers would produce positive outcomes, without the need for what some might see as a rather heavy-handed statutory requirement. Indeed, the industry collectively could have produced its own voluntary code in this area. After all, it has already acknowledged a need to improve its engagement with consumers. In regulation more generally, there is an increasing awareness by governments that regulations also impose costs and should not be made lightly. There are grounds for SCER, the AEMC and the AER to consider whether there are alternatives to these kinds of regulations. At the very least, the AER should provide advice as to how it intends to interpret and apply these Rules.

RECOMMENDATION 21.5

The new National Energy Consumer Advocacy Body proposed by the Standing Council on Energy and Resources should:

- ***have expertise in economic regulation and relevant knowledge and understanding of energy markets***
- ***represent the interests of all consumers during energy market policy formation, regulatory and rule-making processes, merits reviews, and negotiations with providers of electricity networks and gas pipelines***
- ***subsume the role of the existing Consumer Advocacy Panel into its broader functions, but only provide grants to consumer bodies where the research proposal is judged to have merit and unlikely to proceed without some government funding***
- ***ultimately subsume the role of the Consumer Challenge Panel***
- ***receive adequate ongoing funding through a levy on market participants, drawing on the approach used to currently fund the Consumer Advocacy Panel***
- ***have a governance structure that involves an expertise-based board of members appointed on merit, and an advisory panel to give the board advice on the needs of the mix of customers concerned***
- ***be independent from the Australian Energy Regulator.***

The recently commissioned independent review into the best design of the National Energy Consumer Advocacy Body should take these recommendations into account.

21.5 Processes for amending electricity network regulation

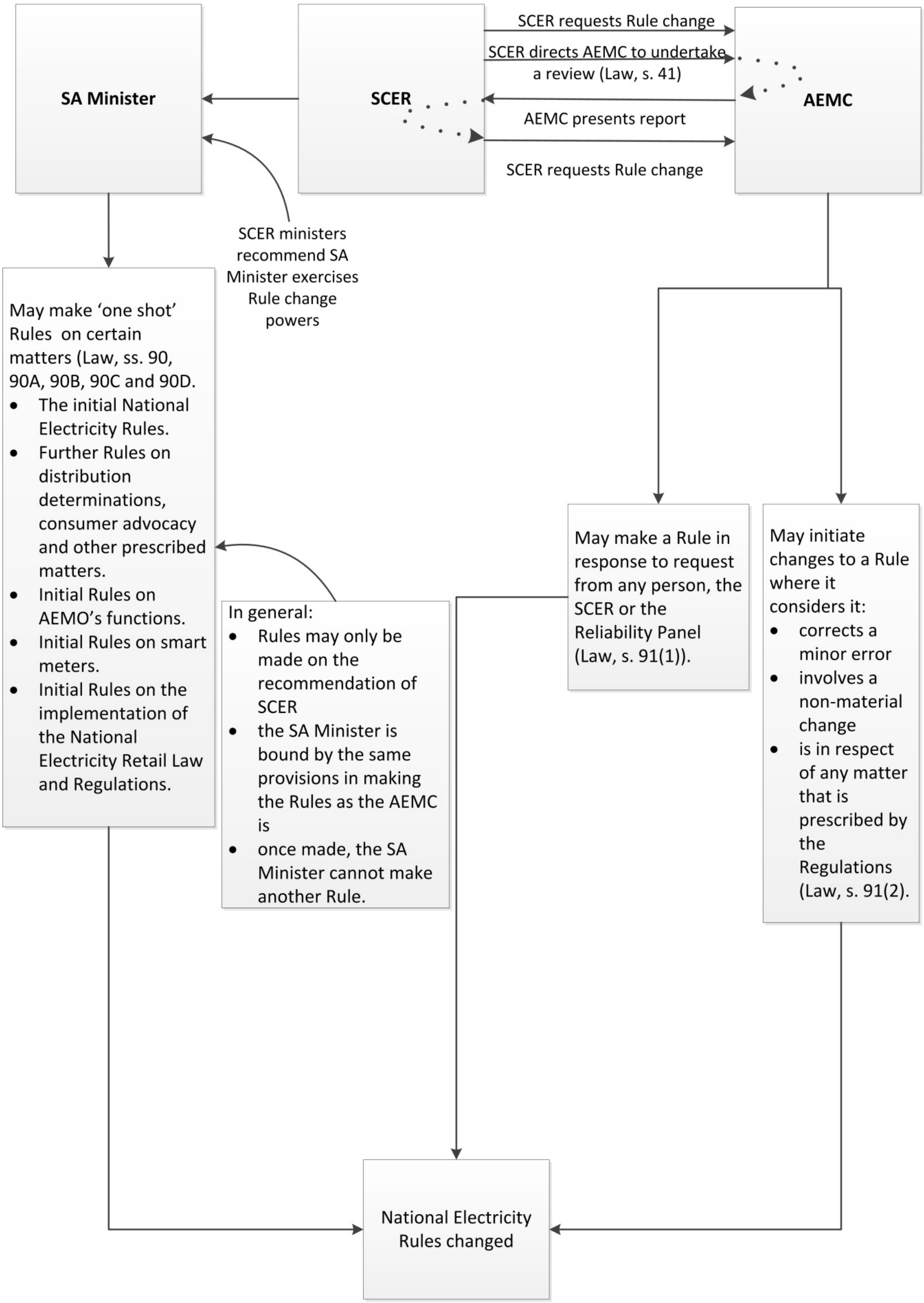
This section examines the processes for policy change in the NEM since these are directly relevant to the implementation of many of the Commission's recommendations in this inquiry. These processes can affect not only the quality of the changes, but the timeliness and cost of implementing them. SCER is responsible for developing energy policy and for changes to the National Electricity Law. However, it does not have power of its own to change the National Electricity Rules,[17] which are the principal source of regulation of the NEM. Instead, the AEMC has responsibility for developing and amending the Rules to achieve the NEO. It initiates changes to the Rules that are minor or prescribed in the Regulations or, on more important matters, responds to requests, including from SCER, to consider and then decide upon changes to the Rules (figure 21.3). An additional critical role of the AEMC is to undertake reviews of its own accord, or as directed by SCER — such as its reviews of transmission frameworks (AEMC 2012j) and demand management (AEMC 2012u). The AEMC provides reports of these reviews to SCER, which can then request Rule changes. Although SCER can set the timetables of reviews in its directions to the AEMC, it is not able to do so in respect of Rule changes.

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). In practice, however, this can take one year to complete
- a fast-track process where: there has been adequate first round public consultation by an 'electricity market regulatory body' (such as the AER or AEMO); or the Rule request is based on an AEMC-initiated review or a SCER-directed review and there was adequate consultation during the review. (Other reviews are not covered by this provision.) This process can take 21 weeks from initiating the process, but is rarely used (AEMC, pers. comm., 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).

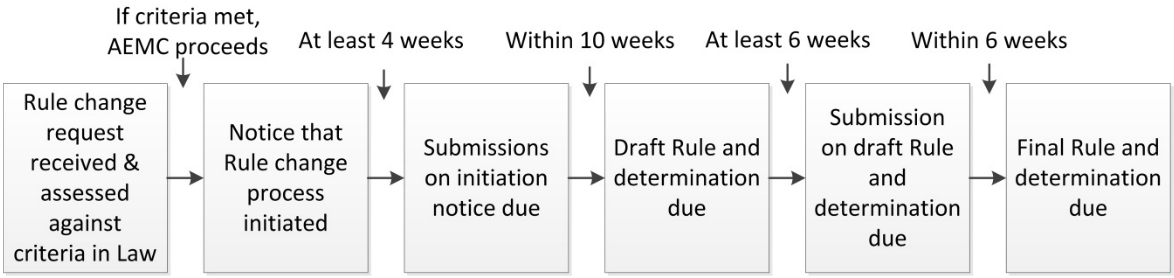
[17] Historically, with the approval of the other energy ministers, the South Australian Minister has had, and exercised, powers to make initial Rules on certain matters. However, the advice given to the Commission suggests that this capacity for making new Rules is now exhausted, so that any further power for SCER to make Rule changes through this route would require amendment of the National Electricity Law.

Figure 21.3 **Pathways to changing the National Electricity Rules**



Data source: National Electricity Law.

Figure 21.4 **The 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 August 2012 and 5 October 2012); AEMC (2012s).

The Rule change processes administered by the AEMC have several desirable features in that they:

- enable NEM participants and others in the community to actively participate in initiating Rule changes
- involve genuine consultation on any Rule change proposals
- are compatible with COAG's regulatory impact analysis framework (PC 2012d, figure 1.3, p. 39) and, in particular, with elements of a Regulation Impact Statement (Department of Finance 2008). 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)
- enable technical changes to be implemented expeditiously.

However, notwithstanding these features, the roles and processes for decision-making in the NEM are, to some extent, poorly defined, slow and cumbersome and, in other ways, counter-intuitively, rapid. They differ markedly from the usual policymaking processes in Australia.

- 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 SCER, parliament or government. Arguably, providing the AEMC with a Rule making power may be an appropriate response to the inertia that is sometimes associated with the difficulties of getting ministerial agreement in COAG bodies. (The struggle to achieve a National Energy Customer Framework exemplifies this concern.) Given the historically parochial nature of energy policy in Australia and the requirement for reasonable nimbleness in making policy changes, this structure was desirable at the commencement of the NEM, but it cannot be said to be conventional or necessarily desirable over the long run.

- While the respective functions of SCER and the AEMC are ostensibly clear, in practice the roles are blurred.
  - In many respects, the AEMC is a policymaker. For example, by any standards, the outcomes of the Rule change involving the economic regulation of network service providers (AEMC 2012r) represents a major policy change. Certainly, outside the NEM, a parliamentary Act making similarly sweeping changes in the regulatory environment would be regarded as a fundamental piece of legislation and policy reform. The 'separation of roles' between SCER and the AEMC claimed by several network businesses is rather indistinct.[18]
  - The corollary of the above is that the distinction between the AEMC's processes in undertaking major framework reviews and Rule making is more semantic than real. Both involve intensive consultation and the consideration of broad policy issues.

Consequently, consideration of the current arrangements should not start with the premise that they are structurally sound. There are grounds for adaptation of the arrangements that move them — even if incrementally — towards conventional policymaking.

Rule change processes need reforming

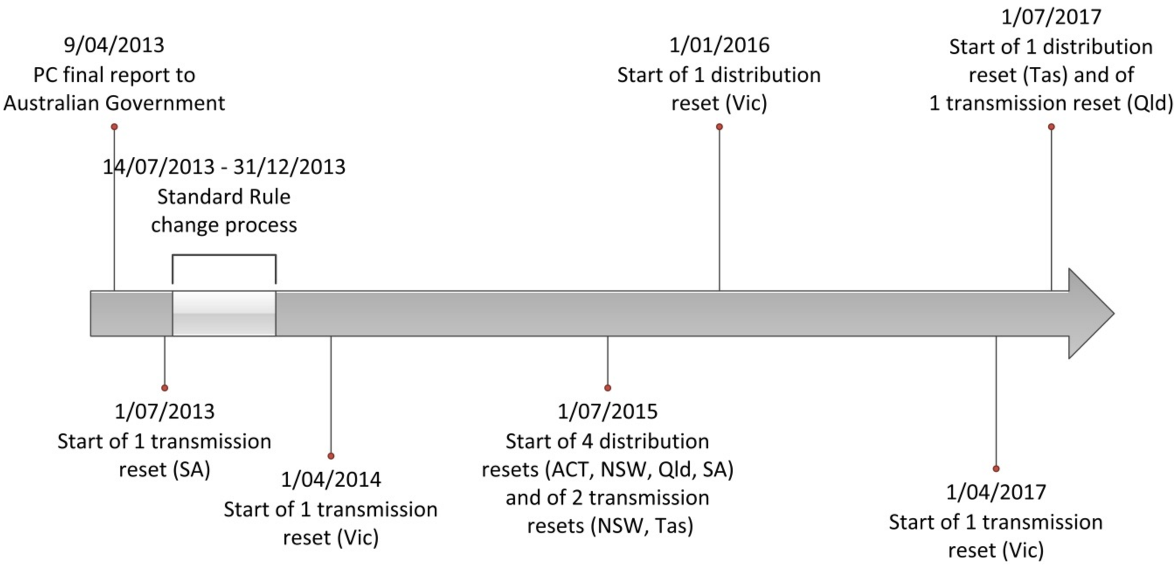
The Commission has not investigated in any detail the full extent of any desirable adaptations, but was struck during this inquiry by an anomaly in policymaking in the NEM compared with other economic sectors. The Commission has undertaken an extensive public inquiry into many aspects of network regulation and made many highly specific recommendations that could be given effect in Rule changes. Other reviews concerning electricity network regulation — for example, the independent panel carrying out the limited merits review commissioned by SCER, the inquiry by the Senate Select Committee on Electricity Prices and, indeed, many of the AEMC's own reviews — may well be in the same boat. Yet, even if SCER considered that any such recommendations should be implemented through the Rules, this could not happen with any speed, if at all. (In contrast, a change to the National Electricity Law could be made quickly, despite the fact that the National Electricity Law and the National Electricity Rules are both statutory instruments giving effect to policy.)

[18] ENA (sub. DR71, attachment A, p. 20) and Ergon Energy (sub. DR63, p. 9).

The adverse consequences of this are that the usual sovereign powers of parliaments are weakened, the benefits from reforms are delayed, there is an added consultation burden on stakeholders, and there is duplication in the resourcing of reviews.

For example, were the standard process for Rule changes to be applied to give effect to the Commission's proposal to reform transmission and distribution reliability by December 2013 (recommendation 21.8), it would need to start before July 2013 (figure 21.5). Delaying this process means that there is a risk that the reforms would not have any beneficial impact on forthcoming regulatory determinations for the most costly part of the system (distribution) commencing in July 2015 (figure 21.5). (The impact of additional processes to those of the Rule change processes in further delaying such reforms are considered later.)

Figure 21.5 **The standard Rule change process within the context of forthcoming regulatory resets[a]**



[a] The standard Rule change process is assumed to take around 26 weeks.

Data source: Dates for start of revenue resets of distribution and transmission — chapter 2, table 2.5.

Improving Rule change processes would reduce inefficiency and accelerate reform

One way in which improvement could be achieved would be for the AEMC, in particular circumstances, to take on a role more akin to a parliamentary drafter, simply translating relevant recommendations from its own and other reviews into Rule changes, together with expediting commentary on these changes.

However, the Commission recognises that any such arrangement would need strong disciplines.

- Rule changes would need the assent of SCER, consistent with the conventional political processes of accountability in a democracy. SCER should decide which recommendations would go through this process.
- Any non-AEMC review would have to meet strict criteria (see below). (The presumption is that previous AEMC reviews would automatically meet these criteria.)
- The draft Rule changes would still be subject to scrutiny and consultation, but *without the policy reasons underlying the Rule change being re-opened.*
- The Rule change process would have a tight timetable and be completed within six months. This tight timetable could be achieved through legislative amendments in the National Electricity Law to existing fast-track and expedited processes, or through the introduction of a new accelerated process.

The Commission's draft recommendation for improving the Rule making process took a rather more expansive form than the above. The Commission recommended that the National Electricity Law be amended to expedite the making of Rules arising from recommendations by non-AEMC reviews by giving both the AEMC the power to expedite Rule change requests and the South Australian Minister a broader power to make Rules with the agreement of SCER (the latter by-passing the AEMC altogether).

The Commission's draft recommendation, particularly the increased role of the South Australian Minister, was met with considerable disquiet by industry participants. On further reflection, the Commission does not consider that such a ministerial prerogative would be necessary as a solution to the particular problem identified above. (However, over the longer term, there may well be benefits in revisiting the overall decision-making processes in the NEM, reflecting the broader issues raised above — but that is neither a matter for this inquiry nor an urgent imperative.)

More broadly, participants were also troubled that acting on non-AEMC reviews could risk losing the checks and balances of existing Rule change processes, such as:

- an inability for stakeholders to have a sufficient say about matters directly affecting them (Alinta Energy, sub. DR81, p. 5; Ergon Energy, sub. DR63, p. 9; GDF Suez Energy Australia, sub. DR68, p. 4)
- a failure to test policy against the NEO — an obligation of existing Rule change processes (Origin Energy, sub. DR64, p. 2)
- the capacity for Rule changes stemming from reviews conducted by 'any number of organisations' (Origin Energy, sub. DR64, p. 7)

- incoherent changes to the Rules as no one organisation would be responsible (ENA, sub. DR71, attachment A, p. 20)
- greater regulatory uncertainty (GDF Suez Energy Australia, sub. DR68, p. 4).

The Commission agrees that any alternative arrangement for achieving Rule changes would need to address these risks. However, having tough disciplines on any eligible review is intended to solve just these kinds of problems.[19] Accordingly, any non-AEMC review used as the basis for accelerated Rule changes would need to comply with the following key criteria.

- The reviewing institution is independent and has the necessary expertise.
- The review is consistent with COAG's regulatory impact analysis framework — for example, the review involves public consultation, considers all the elements of a COAG Regulation Impact Statement, and makes the outcomes of the review public (preferably with a draft report as part of the process).
- The review is sufficiently recent that stakeholder consultations would be against the background of the contemporary regulatory environment (Jemena, sub. DR77, p. 11). This would also recognise that too dated a review would neglect the views of any new stakeholders. (The Commission recognises that its draft report view that a review might be as old as two or three years would not be appropriate.)
- The review contains sufficiently suitable and detailed analysis to support a Rule change proposal.[20]
- The review assesses the proposals against the NEO.
- The review is cognisant of the overall regulatory environment.

Additionally, SCER would need to support the relevant recommendations from such reviews for them to enter the Rule change process. These are tough requirements and would be rarely met. Any such process would ensure adequate consultation and avoid the haphazard introduction of Rule changes.

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[19] Some considered that, subject to such disciplines, a fast-track arrangement would be appropriate (Energy Retailers Association, sub. DR76, p. 10).

[20] The Commission has recently considered the relevance of previous reviews in regulation making in its benchmarking report on regulatory impact analysis (PC 2012d, pp. 135ff).

RECOMMENDATION 21.6

The National Electricity Law should be amended to require the Australian Energy Market Commission (AEMC) to accelerate the process for making Rule changes within six months where they:

- ***are requested by the Standing Council on Energy and Resources, and***
- ***arise from the recommendations of an appropriately conducted independent review, including previous AEMC reviews, relevant to the National Electricity Market.***

There is a broader need to reform SCER's processes

Some of the more critical reforms in the NEM — for example, those relating to transmission and distribution reliability, transmission planning, smart meters and time-based pricing — have already taken far too long. While the Rule change process described above creates one friction for timely and efficient policy change, it is not the main source of slow reform in electricity network regulation. Reform appears to have been frustrated by complex processes, constant and overlapping reviews, and a lack of agreement by relevant governments about either the reforms themselves or the need for more timely progress to a genuinely NEM-wide approach to energy regulation.

This is exemplified by the processes for reforming transmission planning and reliability. Reviews in this area have been ongoing since 2002, increasing in frequency to the extent that several now overlap. These include:

- *Towards a Truly National and Efficient Energy Market* by Warwick Parer (chair) (March 2002 to December 2002)
- *Energy Reform: The way forward for Australia* by the Energy Reform Implementation Group (February 2006 to January 2007)
- *Towards a Nationally Consistent Framework for Transmission Reliability Standards* by the AEMC (December 2007 to August 2008)
- *Reliability Standard and Reliability Settings Review* by the AEMC (March 2009 to April 2010)
- *Transmission Frameworks Review* by the AEMC (April 2010 to March 2013)
- *Electricity Network Regulatory Frameworks* by the Productivity Commission (January 2012 to April 2013)
- *National Electricity Network Reliability Framework and Methodology* by the AEMC (February 2013 to November 2013).

The significant and avoidable costs imposed on consumers by the current institutional arrangements would suggest that (as just one example) the implementation of the Productivity Commission's model for transmission reliability planning should take place as soon as practicable. While some work needed to implement the reforms can begin immediately, such as the collection of estimates of the value of customer reliability and the development of national probabilistic modelling by AEMO, it now appears that the actual operation of the new approach will be delayed because of the newly announced AEMC review into national electricity network reliability framework and methodology (SCER 2013b). This review will also examine options for national models for transmission reliability planning and will not be completed until November 2013. Following this review, further steps will still be required before reform can be implemented in forthcoming regulatory determinations, including:

- the need for SCER to agree on an implementation plan, which would provide detail on required Rule and legislative changes. The implementation plan would not be considered until June 2014 under the current timetable if the recommendations of the review are agreed in November 2013
- the need for SCER to request a Rule change. The time taken to make such a request could readily take months, unless the matter was treated urgently
- the time taken to complete a standard Rule change process in practice would take at least one year
- a sufficient period of time for transmission businesses to develop their regulatory proposals based on reasonable certainty about the reliability and planning regime (that is, after the Rule change) — around three to six months prior to the submission to the AER
- the timing of forthcoming regulatory determinations (figure 21.5 and table 2.5 in chapter 2) and length of the determination process (between 11 and 15 months).

The upshot of these constraints is that SCER could commit to the Commission's framework in late 2014, but that its actual application in a regulatory determination would not begin until 2017 for Powerlink, and over the following five years for the remaining transmission businesses.[21] In fact, delays in any of the above steps mean

[21] If all deadlines under SCER's timeframe are met, a Rule change to implement the new transmission planning and reliability framework would not be completed until mid-2015. This would be too late for TransGrid and Transend to include into their revenue proposals, which are due on 31 May 2014. Similarly, for Victoria, where regulatory proposals are due by 31 October 2015, there will not be sufficient time for SP AusNet to implement the new regime in its proposal. In particular, it would require additional time to implement the reforms compared with other transmission businesses as it would now have to undertake augmentation planning activities which were previously conducted by AEMO.

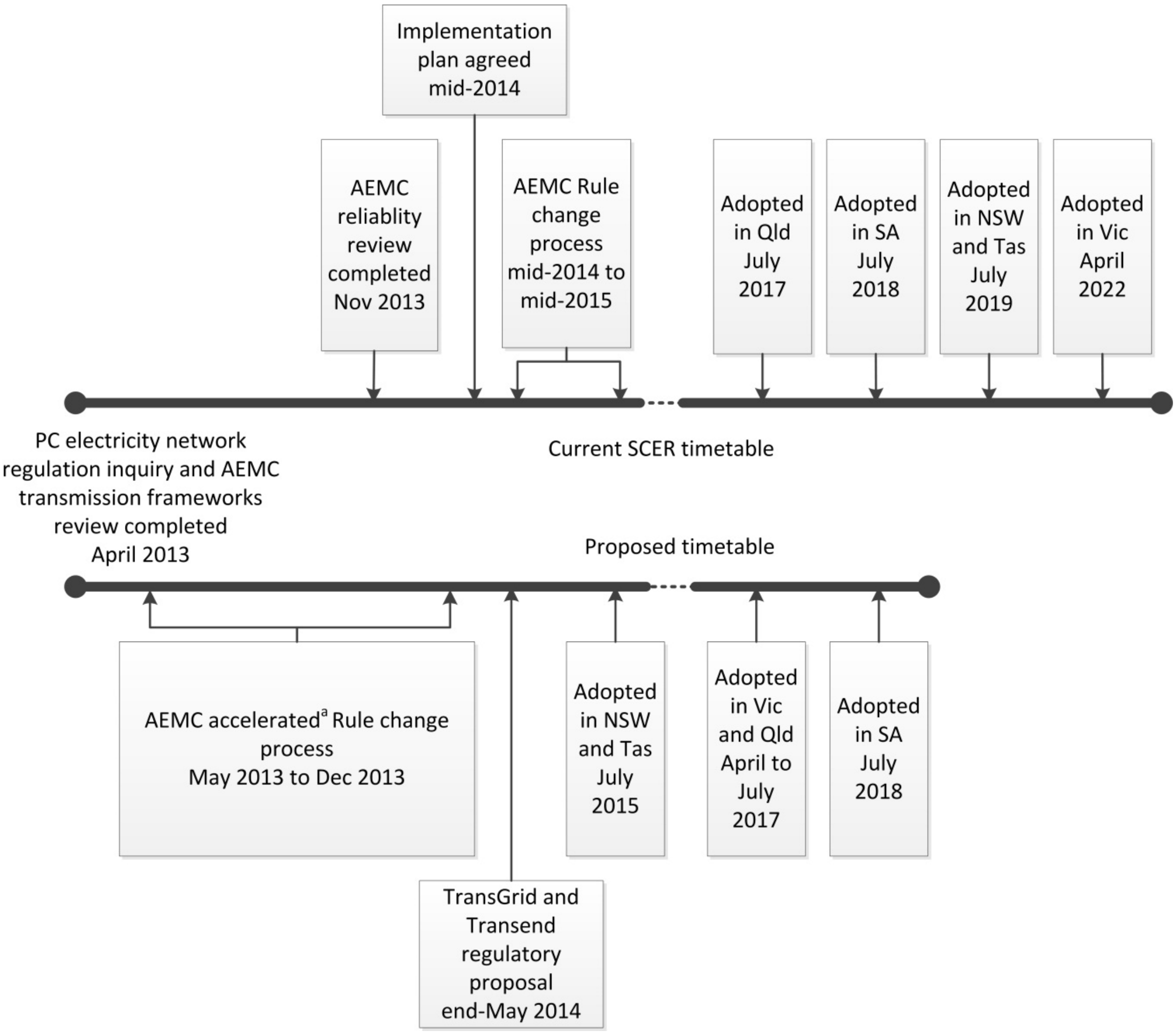
that the process might not even be complete in time for Powerlink's regulatory period beginning July 2017 (but for which regulatory proposals are due by 31 January 2016).

This is despite the fact that reform of this area is one of the most critical components to enable achievement of the NEO. Delay will cost consumers hundreds of millions of dollars of avoidable costs to their electricity bills. It appears that consumer interests have been subordinate to process. Yet, paradoxically, all governments, transmission businesses, AEMO, and the AEMC have agreed to many elements of the reforms suggested by the Commission (or close alternatives to these).

It is therefore an imperative that SCER reforms its processes and expedites its decision making so that critical NEM policy reviews, Rule changes and their implementation occur in a timely fashion. In the case of transmission (and distribution) planning reforms, the Commission's inquiry, along with recently (or soon to be) completed AEMC reviews, directly overlap with the terms of reference for the AEMC's new review into network reliability (SCER 2013b). In the Commission's view, the recent reviews, which have involved wide consultation with stakeholders, along with several relevant earlier reviews, provide the necessary evidence to support reform recommendations in this area. Moreover, ample evidence exists that the cost to consumers of further delays to reform is large.

Accordingly, the Commission believes that the latest AEMC review into network reliability should be converted into an accelerated Rule change process, consistent with recommendation 21.6, to be completed by December 2013. Even an accelerated Rule change process will provide adequate opportunity for further stakeholder input through the AEMC's consultation processes without the need to revisit the case and nature of reforms — aspects that have already been the subject of a number of previous reviews. Following the Commission's approach would allow reforms to transmission reliability planning to begin to take effect in the next round of regulatory determinations, starting in July 2015, with reforms becoming operational across the NEM by 2018 (figure 21.6). The Commission conservatively estimates that the benefits from bringing forward transmission reliability reforms alone would be in the order of $500 million (in present value terms over 30 years), but could be as high as $800 million (appendix F). The significant delays that would be caused by proceeding with the current review would therefore be very costly for Australian consumers.

Figure 21.6 **Timelines for implementing reliability reforms**



a Assumes the accelerated Rule change process reflects the Commission's recommendation 21.6.
Data sources: AER (2013c); chapter 2, table 2.5.

RECOMMENDATION 21.7

The Standing Council on Energy and Resources should reform its processes and decision making so that critical policy reviews of the National Electricity Market, the corresponding changes to the National Electricity Rules, and their implementation occur in a timely fashion.

RECOMMENDATION 21.8

The Standing Council on Energy and Resources (SCER) should convert the current Australian Energy Market Commission's (AEMC's) review of distribution and transmission reliability into an accelerated Rule change process (as set out in recommendation 21.6) to be completed by December 2013. SCER should request the AEMC to draw on the Productivity Commission's recommendations 15.1, and 16.1 to 16.7, as well as the quantitative assessment of the benefits of the recommended reforms, in formulating the proposed Rule changes.

21.6 Merits review processes

COAG and SCER have established a plan for implementing reform of the limited merits review regime (COAG 2012, pp. 3-4), following the findings and recommendations of the Limited Merits Review Panel (Yarrow et al. 2012c). SCER has commenced a regulatory impact assessment process.

Many of the Panel's observations are consistent with the tenor of this inquiry report, though the Commission has not examined the issue of whether a new merits review body is warranted.

Were governments to create such a new body, an important issue is how it would fit within the existing institutional arrangements of the NEM. Having looked closely at these arrangements, the Commission questions the overall benefits of the Panel's recommendation that the body should be attached to the AEMC (Yarrow et al. 2012c, pp. 52ff). The Panel's proposal is that, while the review body would operate as an independent body, the AEMC would provide administrative support and expert resources. The Panel proposed that there be regular, periodic meetings between AEMC commissioners and the review body's members to discuss regulatory supervision.

The Panel recommended this arrangement for several reasons.

First, there would be administrative resource savings from co-location within an existing body. On the other hand, the Panel observed that other agencies could also serve this role, and so this is not a decisive factor.

Second, the AEMC has strong expertise in energy matters. This is true. However, its expertise is greater in legal and economic matters than in engineering, which various parties have nominated as critical, including the Limited Merits Review Panel (Turvey 2000b; Yarrow et al. 2012c, p. 24). While the existing Tribunal has the advantage of having experience in many other technical infrastructure matters, such as in telecommunications and other essential facilities of national significance, it too lacks engineering expertise. However, other parties could provide expertise, such as through secondments to the merits review body or simply as expert witnesses.

Finally, the Panel considered that both the AEMC and the merits review body shared a common function, serving as constraints on the conduct of the regulator — the former through the Rules and the latter through the ex post assessment of any regulator's decisions disputed by relevant parties:

> We have noted that rule changes currently under consideration by the AEMC tend to have the effect of affording the AER greater discretion in its decision making. Again, in a well functioning regime, it might be expected that any reduction in supervision *ex ante* (i.e. via rules) might well be accompanied by adjustments to supervisory arrangements that operate on an *ex post* basis, as appeals/review processes do. At a minimum, if the primary regulator is given more discretion, it might be expected that there would be some simultaneous consideration of whether, on standard checks and balances arguments, the extra power/discretion granted merited some counter-balancing adjustment in supervisory arrangements. The panel therefore sees merit in having these two aspects of supervision — via rules and via the oversight of standards of (primary decision making) performance — which need to be coordinated in some way or other, under the same organisational roof. (Yarrow et al. 2012c, pp. 52-3)

Nevertheless, this argument has some flaws. In particular, the discretion that the AER possesses under the new arrangements are a *consequence* of decisions by the AEMC, and not a policy accident that requires extra supervision by the AEMC. Were the AEMC suspicious of discretion, it should not have made the Rule change, or it should have introduced safeguards against its abuse within the Rules. For sure, if it all ends in tears, the AEMC can make further amendments to the Rules, but it does not need the review body as a bedfellow to do this.

As discussed earlier, the AEMC sometimes serves as a de facto policymaker, and in that context, it is highly questionable that it should have any closer relationship with the merits review body than any other stakeholder. Review bodies are best the cold and distant relatives to policymakers.

A Conduct of the inquiry

The Commission received the terms of reference for this inquiry on 9 January 2012. It subsequently released an Issues Paper on 23 February 2012 inviting public submissions and indicating some particular matters on which it sought information.

In total, 109 public submissions were received and placed on the inquiry website. A list of all public submissions is contained in table A.1.

During the course of the inquiry, the Commission held informal consultations with governments, regulatory bodies, peak industry groups in the electricity sector, as well as a number of companies and individuals. Table A.2 lists these participants.

The Commission released a Draft Report for public comment on 18 October 2012. It subsequently hosted a series of roundtables to discuss the report (table A.3).

Public hearings to discuss the Draft Report were held in Melbourne, Sydney and Canberra in late November and early December. A list of participants at the public hearings is contained in table A.4.

The Commission would like to thank all those who contributed to the inquiry.

Table A.1 Public submissions received[a]

Participant	*Submission No.*
ActewAGL	14, DR59
ACT Government	DR75
AGL Energy Limited	27, DR86
Alinta Energy	DR81
Alternative Technology Association	DR87#
AMP Capital Investors Limited	DR55
APA Group	2
Ausgrid	19
Australian Academy of Technological Sciences and Engineering	9
Australian Energy Market Commission	16, DR89
Australian Energy Market Operator	32*, 42#, DR100*
Australian Energy Regulator	13, DR92, DR104, DR109
Australian Services Union	DR57
Brand, Paul	DR53
Business SA	1
City of Sydney	39, DR58
Clean Energy Council	31, 38, DR97, DR106
Consumer Action Law Centre	5, DR79#
Copper Development Centre Australia Ltd	3
Macquarie Corporate and Asset Finance Limited	DR54
Credit, Commercial and Consumer Law Program, Queensland University of Technology	10
CS Energy	DR67
Cunningham, Michael	28, DR84
Department of Primary Industries (Vic)	34, DR94#
Energex Limited	20
EnergyAustralia (formerly TRUenergy)	4, DR82
Energy Networks Association	17, 40, 43, DR71#
Energy Retailers Association of Australia	DR76#
Energy Supply Association of Australia	23, DR70
Energy Users Association of Australia	24, DR60
EnerNOC Pty Ltd	7, DR83
Ergon Energy	8, DR63
Essential Energy	30
ETSA Utilities, CitiPower, and Powercor Australia	6
GDF SUEZ Energy Australia (formerly International Power – GDF Suez Australia)	36*, DR68
Gill, Martin	DR51
Grid Australia	22, 37, 44#, DR91, DR101, DR103, DR105
Hughes, Alan	DR78#
Hydro Tasmania	41, DR96
Jemena Limited	21, DR77
Landis+Gyr	DR95
Lively, Mark B	DR108

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Table A.1 **(continued)**

Participant	*Submission No.*
Loy Yang Marketing Management Company	25
Major Energy Users	11, DR66
Master Electricians Australia	DR74
Melbourne Energy Institute	DR73
Mountain, Bruce	DR49
National Generators Forum	33, DR93
National Seniors Australia	DR62
NSW Business Chamber	DR52
NSW Distribution Network Service Providers	DR85#
Northern Alliance for Greenhouse Action	DR88
Origin Energy	DR64
Pacific Economics Group	35, DR48, DR107
Palmer, Graham	DR46
Public Interest Advocacy Centre	26, DR65
Queensland Treasury Corporation	12
Richardson, John	DR45
CitiPower, Powercor Australia and SA Power Networks (formerly ETSA Utilities)	DR90
Sinclair Knight Merz	DR61
SP AusNet	18, DR69, DR99, DR102
Sustainable Regional Australia	DR72
Total Environment Centre Inc	15, DR50
Tunstall, Ian	DR56
United Energy	29, DR80
Visy	DR98
Walker, Mark D	DR47

a A hash (#) indicates that the submission includes attachments. An asterisk (*) indicates that the submission contains confidential material NOT available to the public.

Table A.2 **Meetings**

Participant
Commonwealth and national
Australian Competition and Consumer Commission
Australian Energy Market Commission
Australian Energy Market Operator
Australian Energy Regulator
Australian Power and Gas
Department of Finance and Deregulation
Department of Resources, Energy and Tourism
Energy Networks Association
Energy Retailers Association of Australia
Energy Supply Association of Australia
Energy Users Association of Australia
EnerNOC
Ergas, Henry
ERM Power
Fearon, Paul
Grattan Institute
Grid Australia
Infrastructure Australia
Infrastructure Partnerships Australia
Jemena
Landis+Gyr
Nuttall Consulting
Tamblyn, John
The Treasury
Australian Capital Territory
ActewAGL
Environment and Sustainable Development Directorate
Treasury Directorate
New South Wales
Ausgrid
Department of Premier and Cabinet
Department of Trade and Investment, Regional Infrastructure and Services
Essential Energy
Institute of Sustainable Futures, University of Technology Sydney
Independent Pricing and Regulatory Tribunal
The Treasury
TransGrid

(Continued next page)

Table A.2 **(continued)**

Participant
Queensland
Department of Energy and Water Supply
Department of the Premier and Cabinet
Energex
Ergon Energy
Independent Review Panel on Network Costs
Powerlink Queensland
Queensland Treasury and Trade
QEnergy
South Australia
Department of Manufacturing, Innovation, Trade, Resources and Energy
Department of Treasury and Finance
ElectraNet
Essential Services Commission of South Australia
SA Power Networks (formerly ETSA Utilities)
Tasmania
Basslink
Department of Infrastructure, Energy and Resources
Department of Treasury and Finance
Hydro Tasmania
Office of the Tasmanian Economic Regulator
Transend Networks
Victoria
CitiPower and Powercor Australia
Department of Premier and Cabinet
Department of Primary Industries
Energy Safe Victoria
Essential Services Commission
SP AusNet
United Energy
Victorian Competition and Efficiency Commission
Western Australia
Department of Finance
Department of Treasury
Overseas
Federal Energy Regulatory Commission (US)
Hogan, William
Littlechild, Stephen
Ofgem (UK)

Table A.3 **Roundtables**

Organisation	*Participant*
Canberra – 12 November 2012	
Ausgrid	Neil Gordon
Australian Energy Market Commission	Rory Campbell
	Electra Papas
Australian Energy Regulator	Chris Pattas
Choice	Katrina Lee
Energy Networks Association	Susan Streeter
Energy Retailers Association of Australia	Ramy Soussou
Energy Users Association of Australia	Bruce Mountain
EnerNOC	Paul Troughton
Landis+Gyr	Milan Vrkic
Oakley Greenwood	Lance Hoch
Department of Primary Industries (Vic)	Graham Dawson
Sydney – 19 November 2012	
Australian Energy Market Commission	Chris Bangaro
	Paul Smith
Australian Energy Market Operator	Louis Tirpcou
	David Swift
Australian Energy Regulator	Mark Wilson
	George Huang
ElectraNet	Rainer Korte
Energy Users Association of Australia	Bruce Mountain
Grid Australia	Peter McIntyre
South Australian Department of Planning, Transport and Infrastructure	Rebecca Knight
SP AusNet	Kelvin Gerbert
University of New South Wales	Hugh Outhred
Department of Primary Industries (Vic)	Mark Feather

Table A.4 **Public Hearings**

Individual or organisation	*Transcript page numbers*
Melbourne – 27 November 2012	
CitiPower and Powercor Australia	4–19
SP AusNet	20–40
Hydro Tasmania	41–58
Sustainable Regional Australia	59–74
Consumer Action Law Centre	75–89
Energy Users Association of Australia	90–110
Sydney – 3 December 2012	
Australian Energy Regulator	113–135
Landis+Gyr	136–159
Energy Supply Association of Australia	160–177
Major Energy Users	178–201
City of Sydney	202–216
AGL Energy	217–234
Public Interest Advocacy Centre	235–248
Canberra – 6 December 2012	
Smart Grid Australia	251–270
Department of Primary Industries (Vic)	271–287
Grid Australia	288–315
Canberra – 10 December 2012	
Australian Services Union	318–328
Energy Networks Association	329–350
National Generators Forum	351–373
EnerNOC	374–389
Australian Energy Market Operator	390–422

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—— 2011d, *Environmental issues, Energy use and conservation*, Cat. No. 4602.0.55.001.

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