Garnaut
CLIMATE CHANGE
REVIEW UPDATE 2011

Transforming the electricity sector

Update Paper 8

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Update Paper eight:

Transforming the electricity sector

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TRANSFORMING THE ELECTRICITY SECTOR

Key points

- The electricity sector will respond strongly to reduce emissions with carbon pricing.
    - There will be early switching of fuels, especially from coal to gas and an increasing focus on less emissions-intensive forms of generation.
- With or without a carbon price, a significant amount of investment in generation capacity will be required in the years ahead, reflecting the age of generation assets.
- The introduction of a carbon price is highly unlikely to threaten physical energy security.
    - Nevertheless, it may be prudent to implement cost effective policy measures to assuage concerns about energy security and to improve the regulatory functions of the energy market. These measures include:
        - the introduction of an Energy Security Council to implement measures to counter energy market instability regardless of the source; and
        - the judicious provision of loan guarantees to high-emissions generators through the transition to carbon pricing.
- While electricity prices will rise in coming years, the increase associated with a carbon price is in fact smaller than recent increases.
    - Increased capital costs, and rising gas and coal prices from the resources boom will contribute to higher electricity prices in the years ahead.
- The recent electricity price increases have mainly been driven by increases in the costs of transmission and distribution.
    - There is a prima facie case that weaknesses in the regulatory framework have led to overinvestment in networks and unnecessarily high prices for consumers.
    - The upcoming review of regulatory arrangements by the Australian Energy Regulator presents an opportunity to correct distortions in current regulations.
- There can be large gains from planning transmission for a truly national electricity market, with greater inter-state connectivity increasing competition, resilience against supply shocks, and reducing the cost of connecting new low-emissions power sources.
    - Other and more expensive power generation mitigation measures, especially the renewable energy target and subsidies for new roof top solar, can be phased out as the carbon price rises, or feed-in tariffs replaced immediately by more efficient measures for new investments.
- Electricity price effects from the introduction of a carbon price on low- and middle-income consumers can be offset by efficiency-raising tax and social security reform and supplementary measures.
    - Other sources of price increases can probably be greatly reduced with more efficient regulation.

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1. Introduction

The transmission of a carbon price through to household and business electricity prices will drive the development of low-emissions generation and, more generally, lower emissions in the electricity sector. This will involve a switch in the predominant sources of power used in generation. It will involve the building of new low-emissions generation. It will involve the closure of high-emissions generation. It will also moderately reduce the growth in electricity demand in the short term, and more strongly over the longer term as users economise on electricity use. An appropriate carbon price will drive this change and Australia's National Electricity Market is well placed to respond to the carbon price signal.

The response of electricity suppliers to the new incentives structure will be faster and stronger, and the effect in increasing electricity prices smaller, if the carbon price is accompanied by fiscal support for research, development and commercialisation of low-emissions electricity generation, distribution and transmission technologies.

For households, the price increases associated with the introduction of a carbon price come at a difficult time, with recent and prospective large non-carbon-price-related electricity price rises. The increases have come mainly from investment in distribution. Without changes in regulatory policies, large increases in retail electricity prices can be expected for some years, greatly exceeding and creating a difficult environment for increases associated with a carbon price. The effects of the resources boom on coal and gas prices and construction costs are likely to increase substantially electricity costs and prices in the period ahead. The effects of carbon pricing will further increase costs and prices—smaller than the increase in distribution costs over recent years, but still considerable.

Any inefficiencies in the domestic energy markets or regulatory regimes warrant early analysis and correction, especially if they are leading to unnecessary price rises. Improvements to regulatory markets will both ease the adjustment to carbon-related price rises and improve the welfare of Australians. The increase in effective competition and economically efficient regulation and provision of transmission and distribution services are the main factors in limiting the rate of increase in costs. The price controls that remain in all states except Victoria should be removed in each jurisdiction once arrangements have been made to secure effective competition.

This paper discusses the impact of the carbon price on changes in electricity supply over time, and on prices. The effects of other sources of price increases are also examined—both those that are unavoidable, and those that may be the result of regulatory and structural imperfections in the National Electricity Market. There are signs that lower growth in demand is reducing the need for investment. In addition, improving the regulation of the electricity market would reduce pressures for price increases. It is possible that these developments could go a long way towards offsetting the addition to electricity prices of the introduction of a carbon price.

The National Electricity Market covering the five Eastern States and the Australian Capital Territory, as it has emerged from reform over the past two decades, has many fine features. In some ways it is the most advanced electricity market in the world. But these strengths persist alongside a few weaknesses that are at once significant in their effects on the price of electricity, on energy security and the capacity to adjust to the imperative to reduce emissions, and readily correctible. Further reform is a matter of urgency, since it would affect adjustment to a carbon price and the movement to a low-emissions economy. The most important outstanding reform relates to regulation of investment in transmission and distribution networks. Recent developments in planning of transmission can usefully be extended.

The introduction of a carbon price will change the choice of fuel sources, move investment decisions toward low-emissions forms of generation and unlock the possibilities of new technologies by driving innovation. It is important to maintain confidence in security of electricity supply as the transition proceeds. Actual or perceived threats to energy security will be a stumbling block to the transformation that is to come and it is prudent to examine policies to deal with any substantial sources of concern.

Such an examination is best conducted in the context of review of the regulatory arrangements in the electricity sector more generally, as the substantial sources of concern can be present independently of the introduction of a carbon price.[1]

Section 2 of this Update Paper examines recent trends in electricity prices and the drivers of these trends. Rising electricity sector network costs are found to be the main contributor to recent and prospective electricity price increases. Section 3 examines the impact of a carbon price on electricity generation and the transition to a low-emissions electricity sector. This is followed in Section 4 by an examination of developments in the electricity transmission network, with particular attention to how well existing arrangements complement the introduction of a carbon price. In Section 5, the network sector of the electricity market is examined closely and reforms suggested. Section 6 briefly comments on measures to assist households, complementing discussion in Update Paper six (*Carbon pricing and reducing Australia's emissions*). Section 7 concludes with a discussion of the future of the electricity sector in Australia.

2. Recent trends in electricity prices

Australian households and businesses enjoyed relatively stable and low retail electricity prices for many decades. Despite recent increases, they continue to enjoy relatively low prices by international standards. However, in recent years there has been a marked step up in Australian household electricity prices. After a long period in which Australian electricity prices rose more or less in line with other prices, they rose much faster than other prices from about 2006. Over recent years, Australian electricity price increases have outpaced other advanced economies (Table 1 and Figure 1).

From 2007 to 2010, electricity prices for households nationally rose by 32 per cent in real terms (ABS 2010c). While there is some variation in the extent of price rises across the states and territories, they display a consistent upward trend in prices over this period. These increases have been well ahead of the general increase in prices and faster than growth in average wages. While the consumption of electricity makes up a relatively small component of a typical household's expenditure, these price rises are putting pressure on lower income households.

Electricity prices for businesses have also increased rapidly since 2007. While household and business electricity prices have not always moved together, due largely to the presence and unwinding of cross subsidies between the two, recent price rises are common across both customer types.

Electricity price increases are set to continue under current policies and regulatory arrangements. In those states in which electricity prices are regulated for residential and household consumers, further price increases have been announced. In the states (New South Wales and Tasmania) that have made decisions on electricity prices beyond 2011, annual price rises of around 10 per cent are expected over 2011-12 and 2012-13 (IPART 2010a, OTTER 2010). These expectations do not contain allowance for a carbon price.

Rapidly rising electricity prices and the prospect of further increases have raised concerns about the effects of the introduction of a carbon price. In the following sections I will show that the increase in electricity prices that arises from a carbon price is smaller than recent increases. Moreover, as I outlined in Update Paper six (*Carbon pricing and reducing Australia's emissions*), low income households should be fully compensated for increases in costs due to the carbon price. In this respect, electricity price rises that result from a carbon price are different from price increases from other sources, for which no compensating tax, social security and supplementary measures are available.

Nevertheless, the unusually large increases in electricity prices from other sources raise sensitivity to increases associated with the carbon price. This adds to the good reasons for ensuring that the

[1] For analysis of the implications of climate change policies for the South-West Interconnected System of Western Australia, see AEMC (2008a).

electricity market is operating efficiently during the transition to low emission electricity generation and not causing price increases that are unnecessary on economic grounds.

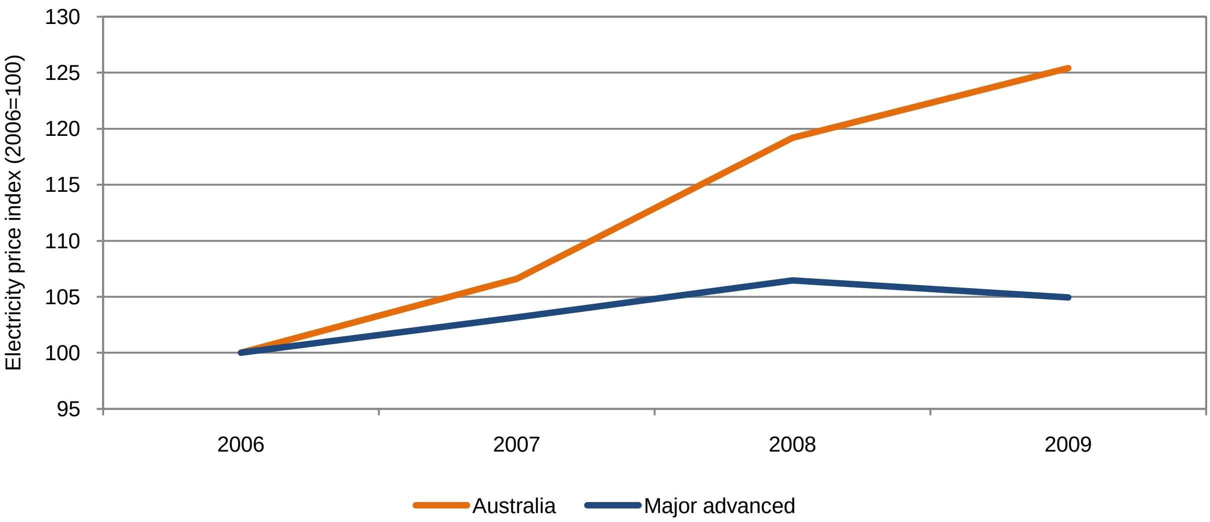
Table 1: Consumer Price Index - Electricity

	Average annual inflation Per cent			Household electricity price[a] Share of income per capita
	1990–1999[b]	2000–2009	Year to latest	2009
Australia[c]	1.6	5.0	12.4	2.8
Canada	3.3	2.5	8.1	1.9
France	na	0.8	3.1	2.8
Germany	0.7	4.5	3.3	6.3
Japan	–0.7	–0.8	3.0	5.1
United Kingdom	–2.8	6.0	–0.4	5.6
United States	0.9	4.2	0.6	2.6

(a) Price per 10 MWh, in local currency; where 2009 price level data were not available, the latest available data were extended to 2009 using CPI electricity prices; United States price includes tax
(b) Data from 1991 for Germany, and from 1996 for the United Kingdom
(c) Adjusted for the tax changes of 1999–2000
Sources: ABS; International Energy Agency; RBA; Thomson Reuters

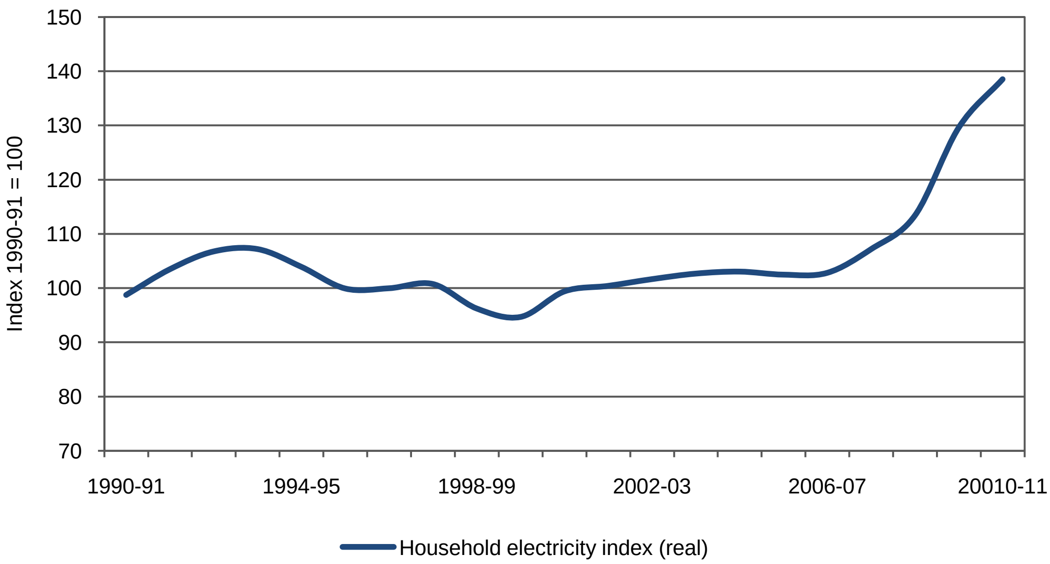
Source: Plumb and Davis (2010)

Figure 1: Real electricity prices in Australia and the seven major advanced economies, 2006 to 2009, index in US dollars



Source: IEA 2009, OECD 2010.

Figure 2: Real household electricity price movements
(constant 100 would mean electricity prices rising at same rate as other prices)



Source: Australian Bureau of Statistics, Consumer price index for electricity (Category 6401.0).

2.1 Drivers of electricity prices

The increases in electricity prices reflect many factors including increased investment in electricity networks (the poles and wires that distribute electricity from power plants to the home) as well as policy changes (such as the Renewable Energy Target) that have led to higher costs (Sims 2010).

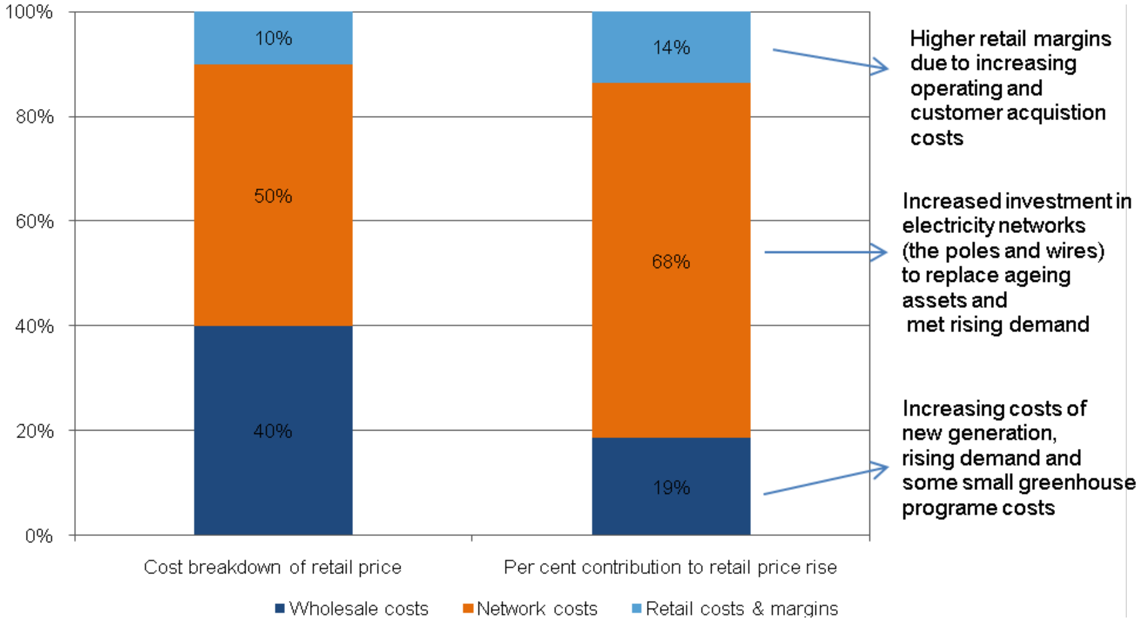
In the future, rising network costs and government policies—unless changed—will continue to contribute to large electricity price rises. In addition, rising generation costs due to high construction costs through the resources boom, higher coal and gas prices, and the introduction of a carbon price—will also contribute. Of these likely drivers of future price increases, households will only be compensated for the introduction of a carbon price.

One way to explore the increase in prices is to examine how costs have changed for the three components of electricity prices—the costs of generating the power, the cost of distributing it to households, and the cost of billing and selling electricity to the households.

The costs of generating power, or wholesale electricity costs, accounted for around 40 per cent of the overall electricity price in 2009. The cost of moving power to households—transmission and distribution costs—made up about 50 per cent of the price. About 10 percentage points of the movement costs are for transmission and 40 per cent for distribution. The retail costs, which represent about 10 per cent of the overall bill—include energy retailers' costs and margins in acquiring and servicing customers through billing, marketing and other means and the trading of electricity between generators and retailers.

Figure 3 illustrates the relative contribution of these components towards current price rises. Rising network costs are the greatest factor in rising electricity prices, accounting for approximately 68 per cent of recent price rises. Wholesale electricity costs and retail costs are also placing some upward pressure on prices: approximately 19 per cent of recent rises can be attributed to increases in wholesale prices while 14 per cent can be attributed to retail cost allowances. Proportionate increases are much larger for networks and retail than for generation.

Figure 3: Electricity costs and their contribution to current price rises in 2010

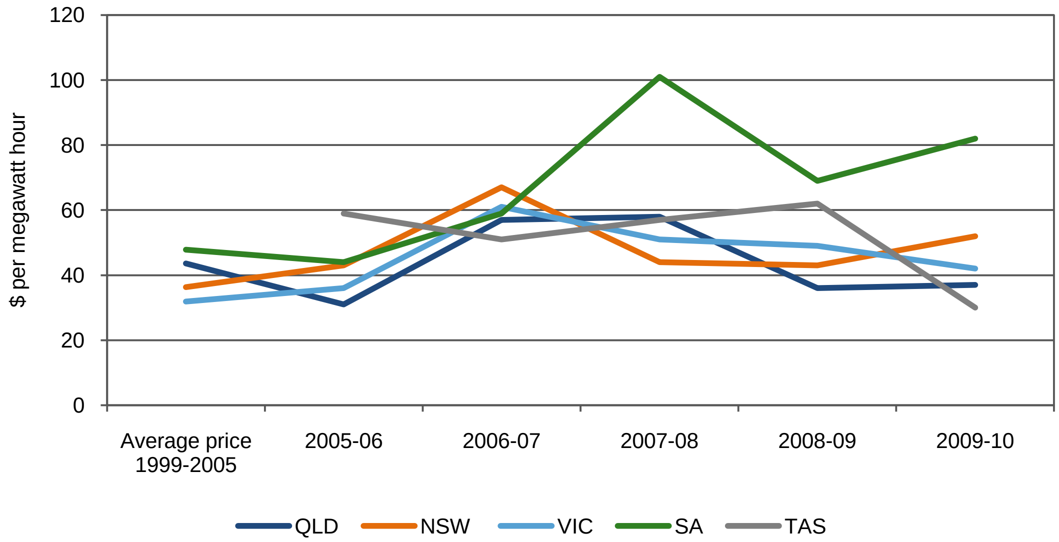


Sources: The contribution of the cost components to electricity price rises is based on an average of the current regulated retail price determinations across jurisdictions in the National Electricity Market (except Victoria which no longer regulates prices) (QCA 2010, IPART 2010a, ICRC 2010, OTTER 2010, ESCOSA 2010).

Electricity generation or wholesale costs

In most of Australia the wholesale electricity market is competitive and therefore wholesale prices are determined primarily by the dynamics of supply and demand. Over the past three years, there has been an easing in the growth in demand. Higher electricity prices reflecting mostly higher network costs have led to consumers moderating their demand for electricity. Over the past year, milder weather reduced the summer demand; industry sources also suggest that the insulation program and photovoltaic installations have had some effect.

Figure 4: Weighted average electricity spot prices



Generation prices have fluctuated widely but around a remarkably steady level in the recent years of large increases in retail electricity prices. These have not been a general cause of rising retail electricity prices. Nominal prices in all states in 2010 were below earlier peaks, in most cases by a large amount.

Drought has played a role in price fluctuations in recent years. Drought raised the cost of water-cooled coal fired power stations (and also reduced the output of Snowy and Tasmanian hydro systems). This along with record peak demands and other factors led to average wholesale electricity spot prices in the National Electricity Market rising to record levels in 2006-07 and 2007-08 (AER 2010a). The end of the drought placed downward pressure on wholesale prices from mid 2010.

Box 1: 2008 indicative future wholesale gas costs

Gas-fired electricity generation is based on mature technologies with lower cost structures than renewable energy in the current state of technology and gas prices. With emissions about 40 per cent of those from brown coal and 50 per cent of those from black thermal coal it has the potential to play a major role in Australia's transition until the costs of lower emission technologies fall considerably. Gas-fired generation has low capital costs but high fuel costs compared with other sources of electricity. Relative gas prices in each of Australia's three regional markets (Eastern, Western and Northern) will therefore influence the rate of the switch to gas generation from coal.

Gas-fired generation accounted for around 20 per cent of Australia's installed generation capacity in 2008-09, but only 12 per cent of generated output (ESAA 2010). This reflects its use as the current preferred fuel for peaking and intermediate generation while coal dominates baseload generation.

Gas prices in most of Australia have been historically low and stable by world standards, defined largely by provisions in confidential long-term supply contracts, which account for most wholesale gas traded in Australia. In contrast, gas prices in Western Australia rose strongly to export parity levels upon the expiry and renegotiation of long-term prices. Recent Ministerial Council on Energy reforms have improved transparency and competition in domestic gas markets, increasing information and allowing for trade of gas supply-demand imbalances to occur.

In 2008, the Review foreshadowed the potential for gas price increases above and beyond those predicted in the modelling as a gas export industry emerged in eastern Australia. The export of coal-seam gas is moving towards maturation, and price increases are still in prospect.

The Australian LNG industry is currently comprised of two distinct hubs located in Western Australia and the Northern Territory. Australia's east-coast LNG industry is in the early stages of development with first exports expected from 2014. Western and Northern market gas reserves are in large offshore basins that cannot be economically developed on the basis of domestic demand alone. A lack of competition, exposure to the international LNG market and project development delays have contributed to recent domestic price volatility in Western Australia.

Eastern market coal seam gas reserves are entirely onshore and more easily developed in small increments. The immediate outlook in the Eastern market is for gas prices to remain low as the growth in export capacity lags behind coal seam gas supplies (EnergyQuest 2011). In the longer term, industry views, economic analysis and current pressures on price in long-term contracts suggest that prices in new east-coast domestic gas contracts are likely to rise towards the export parity price due to arbitrage through the international LNG market. On the other hand, increasing global gas supplies including from Australia, Central Asia, the Middle East and the United States, can be expected eventually to put downward pressure on gas prices in the East Asian markets that determine Australian export parity prices.

Switching from coal to gas-fired electricity generation will assist Australia in meeting national emissions reduction targets over the next decade. As a result, electricity prices are expected to become more sensitive to movements in domestic gas prices over the long-term, as the role of gas-fired generation increases.

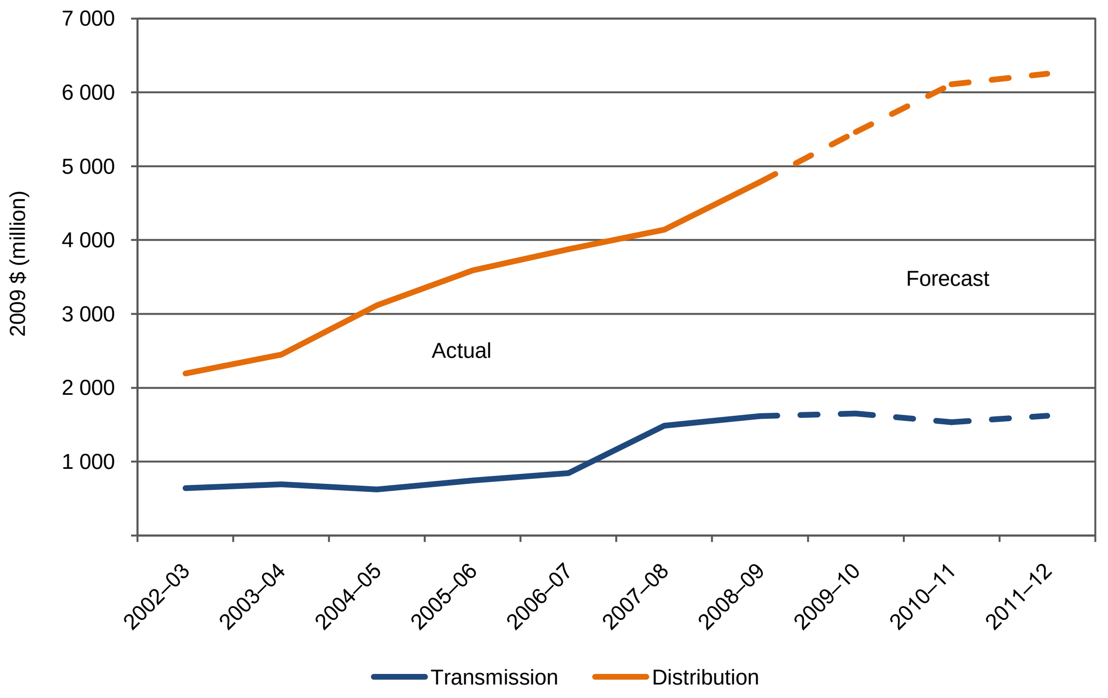
Network costs

The network is composed of transmission and distribution. Network costs refer to the costs of transporting electricity to customers via the establishment and maintenance of the transmission and distribution network. Transmission is the extremely high voltage assets – metal towers connecting generators to substations. Distribution is the lower voltage wiring that brings power from substations to customers. Both are regulated under similar rules.

Network costs have risen dramatically since 2006. The high capital cost of investment required in electricity networks is the single largest cause of recent electricity price rises.

Transmission network investment over the current five year regulatory period[2] is forecast at over $7 billion and $32 billion for distribution networks (AER 2010a). This represents a rise in investment from the high levels of the previous period, of 84 per cent and 54 per cent (in real terms) in transmission and distribution networks respectively (AER 2010a).

Figure 5: Total electricity network investment



Source: AER (2010a). State of the Energy Market 2010. Network investment covers jurisdictions in the National Electricity Market.

These high levels of network investment have been attributed to the need to replace ageing assets, electricity load growth and rising peak demand and changed standards (reliability and service requirements).

While these factors explain some of the increase in network costs, the explanation raises some questions. For example, demand growth has not been particularly rapid in recent times.

Here we present the explanations that the Australian Energy Regulator has provided for the increase in distribution costs.

The need to replace ageing assets

In the recent New South Wales distribution price determinations by the Australian Energy Regulator it is argued that much of the New South Wales network was built between the 1960s and 70s and many parts are now reaching the end of their useful life. The necessary replacement of ageing assets

[2] Current regulatory period revenues are forecast in regulatory determinations (AER 2010a p54)

accounts for around 31 per cent of investment in the New South Wales distribution networks (AER 2009a).

There are questions about whether “economic lives” for any economic assets are uniform and finite; about the bunching of the end of economic lives of assets that were installed over two decades; about the appropriate balance between maintenance to extend life and new capital expenditure; and about whether catching up with past neglect of maintenance is better corrected over short periods or gradually over longer periods.

Changed standards

The costs associated with environmental, safety, statutory obligations, and other system and non-system assets such as IT, and business support are another source of increase in network costs. These are said to make up 18 per cent of investment in New South Wales distribution (AER 2009a).

Load growth and rising peak demand

Rising customer connections off the back of strong population growth are also highlighted in the AER’s recent distribution determinations as a strong driver of investment. For example, for New South Wales distributors a 28 per cent increase in new customer connections per annum by 2013-14, relative to the previous regulatory period, is forecast by the distributors.

Again, there are some questions. New South Wales population growth averaged 1.4 per cent per year between 2005 and 2010 and is projected to slow to 1.1 per cent between 2010 and 2015 (ABS 2008b, 2010b).

In addition to the growing customer base, the Australian Energy Regulator points to the continued growth of average household energy demand as a source for increased requirements of distribution capacity. Figure 6 shows that electricity demand grew much more rapidly than population from 2000 to 2005, but more or less in line with population after that. Industry sources are puzzling over the recent deceleration of growth in electricity consumption, and variously mention the effects of rising prices, the cool summer of 2010-11, and some contribution from improved insulation and other energy efficiency measures and increased use of household photovoltaics, as noted earlier.

The Australian Energy Market Operator predicts that energy demand in the National Electricity Market will continue to increase over the next 10 years at an average yearly rate of 2.1 per cent under a medium growth scenario (AEMO, 2010a).

Australians have been paying more attention to energy efficiency in appliances and buildings. This may have been having some effect on demand. At the same time, other developments are working to offset the tendency for appliances and buildings to be more energy efficient, including:

- Growth in electrical appliance consumption, which is projected (DEWHA 2008) to increase from 71 petajoules in 1990 to 169 petajoules in 2020—almost a 5 per cent increase each year. The number of electrical appliances per household has risen rapidly in recent decades. In addition, a shift in the type, size and usage of appliance is also increasing energy consumption—for example, market penetration of air conditioners has doubled over the past decade.

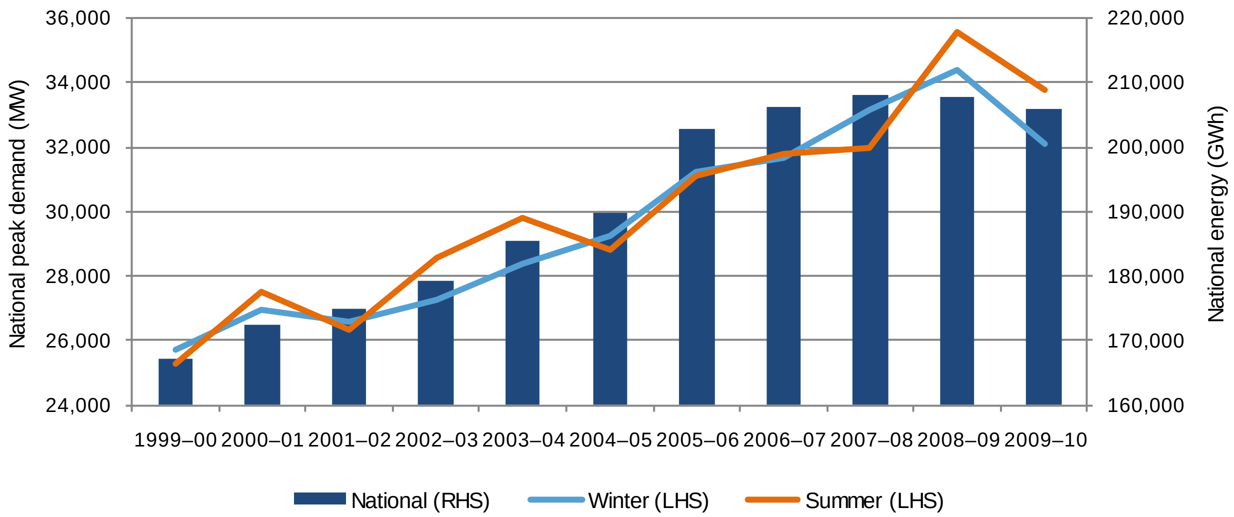
- The rapid increase in the average size of new homes, up by 40 per cent from 1985 to 2009. Australia’s new homes are now the largest in the world—well above those in the US, and almost double those of the UK. This has clear implications for increasing household energy use, particularly related to lighting, heating and cooling (DEWHA 2008; Commsec 2009).

These plausible reasons why the growth in energy demand might be expected to be strong should be set against the evidence that the growth in energy demand has in fact decelerated considerably since about 2006.

It is peak rather than total demand that drives most of the need for network investment. Here one can see influences that could be expected to increase recent demand for distribution services. Through the early twenty first century, the winter peak in demand exceeded the summer peak in some years and fell short of it in others. In the hot summer of 2009-10, the summer peak rose well above the winter peak, and stayed there through the cooler summer of 2010-11 (Figure 6). The summer peak fell markedly in 2010, but this effect is strongly influenced by seasonal conditions.

In Australia, unlike other developed countries, there has as yet been little effort to discourage peak usage of power through variable pricing, smart meters and smart grids (see Section 5). This would seem to offer large opportunity to ease the growth in peak demand.

Figure 6: National energy demand



Source: AER 2010.

Several States have recently adopted higher reliability standards for distribution networks. These require additional capital investment by the network businesses in these states to ensure that the higher standards can be achieved within the regulatory requirements.

The setting of reliability standards and service requirements has not been subject to institutional or regulatory reform. Rather than being based on a probabilistic cost-benefit approach to reliability, most states tend to use a relatively crude and deterministic approach to dictate reliability requirements. This tends to lead to higher standards being imposed than would be the case under a probabilistic approach.

This increase in reliability comes at a cost that is paid by all electricity consumers.

There is no opportunity for consumers to make their own choices on what they are prepared to pay for greater reliability, when standards are already high.

Customer retail services and related costs

The National Electricity Market retail sector is a fully contestable market, except for Tasmania, with private players being able to enter the market and compete for customers. However, these businesses continue to be subject to jurisdictional price regulation, whereby retail prices are capped by the utilities regulator. Victoria is the exception, where the market has been fully deregulated. In determining retail prices, the utilities regulator takes into account a wide range of factors, including the drivers of costs from generation to distribution, and retailer margins.

Box 2: Retail price regulation

Price cap regulation was intended as a transitional measure during the development phase of retail energy markets. The Australian Energy Market Commission reviews the adequacy of competition in retail energy markets to determine an appropriate time to remove retail price caps.

Any decision to remove retail price regulation resides with the relevant jurisdictional government. Victoria is the only jurisdiction to take this decision to-date. The government of South Australia has declined to remove retail price regulation even though the Australian Energy Market Commission advised that there were sufficient levels of competition.

Ongoing cost of living concerns have increased the reluctance of governments to allow prices to be determined in the market. However, as recent price rises have demonstrated, retail price regulation has not helped to constrain the rising costs of electricity.

Moreover, the regulatory uncertainty engendered by current arrangements would tend to suppress the supply response to higher prices. This defeats the notion that price cap regulation provides more assurance to households on lower electricity costs. The tendency to suppress responses to high prices can be present even when the practice is to allow full pass-through of all prices, because suppliers are not certain that they will receive the price increase.

2.2 The costs of government policy

A number of government policies to promote energy efficiency improvements and renewable energy generation are funded from the prices paid by consumers for electricity. These policies therefore contribute directly to higher retail electricity prices, and depending on the level of uptake, have the potential to place further upward pressure on prices. They feed into all three components of electricity costs: wholesale, network and retail components.

These programs generally fall into three categories:

The Renewable Energy Target

Under the Renewable Energy Target scheme, retailers must ensure that a proportion of their electricity supply is from renewable energy sources or face penalties for non-compliance. Renewable energy is a more expensive source of electricity and therefore adds to wholesale electricity prices.

From 1 January 2011, in response to concerns that the Renewable Energy Target price was being suppressed by an unexpectedly large growth in small-scale technologies such as roof-top photovoltaics, the Government split the scheme into a large and small scale technology component.

The Large scale Renewable Energy Target is largely modelled off the original design. The Small scale Renewable Energy Scheme has a fixed price, similar to that of a feed-in-tariff, and electricity retailers are obliged to purchase all Small Renewable Energy Scheme certificates in proportion to their market share. The regulator has set the retailers an obligation to purchase Small Renewable Energy Scheme certificates equalling 14.8 per cent of their 2011 sales, which alone will comprise about 3 per cent of an electricity bill in 2011 (Office of the Renewable Energy Regulator 2011).

When the Renewable Energy Target was first expanded, it was estimated to add approximately 4 per cent to electricity prices in the period 2010 to 2015, or by about 0.8 per cent per annum (MMA 2010). Some state regulators have foreshadowed higher impacts on prices. While these increases may seem small they may turn out to be larger than this estimate, particularly with the high levels of Solar

Photovoltaic uptake in New South Wales that were not foreseen. More importantly, they are unnecessary once the economy-wide carbon price is carrying the load of the transition to a low-carbon economy. The Update confirms the recommendation of the 2008 Review: that the penalty for non-compliance with the renewable energy target requirements should remain fixed permanently in nominal terms, so the influence of the target gradually fades out with time and the increase in the carbon price.

Feed-in-tariffs

Feed-in-tariff schemes pay a premium rate to encourage renewable electricity generation through small scale generation such as solar photovoltaic systems. The costs of these premium rates are spread across all consumers. All consumers cross subsidise those who can afford the up-front capital costs of such systems.

The cost of a feed-in-tariff depends on the scheme design, tariff rate and the level of uptake. There has been relatively strong demand for these schemes in most states. In South Australia, the cost of feed-in-tariffs comprised around 0.5 per cent of an average household electricity bill in 2008-09 (Miley 2009). In New South Wales, the more generous tariff rate led to higher than expected demand and it is said that it would have added 5-10 per cent to retail prices in 2011/12 (Premier of NSW 2011) if it had been left in place. This resulted in a decision by the New South Wales Government in 2010 to reduce the feed-in-tariff payment and to avoid the impact on electricity bills by off-setting the full costs of the Scheme through the State Budget.

Other government policies

Some jurisdictions have also implemented policies and programs which affect the retail electricity price differently depending on scope, scale and design. In most cases the objective of these programs is to encourage energy efficiency, demand management and carbon abatement by requiring retailers or distributors to undertake specific activities. Generally these programs comprise only about 1 to 2 per cent of the retail electricity price. They include initiatives such as the Queensland Gas Scheme, the Energy Savings Scheme in New South Wales, the Greenhouse Gas Reduction Schemes in New South Wales and the ACT, the Residential Energy Efficiency Scheme in South Australia, and smart meters in Victoria.

Victoria began its rollout of smart meters to consumers in 2009 with the aim of reducing peak and overall energy demand by giving consumers the information needed to manage their consumption more efficiently. The rollout costs would have accounted for retail electricity price increases of around 2.5 to 7 per cent in 2010 when the costs were first passed onto consumers—network charges increased on average by almost $70 in 2010 and a further increase of around $8 is expected in 2011. The difficulty with this program is that the meters' capabilities are not being fully utilised, and the payback comes over a number of years, while the costs are readily visible on bills today.

Smart meters can play a major role in reducing electricity demand. They can reduce price increases even more, as a part of systems that encourage and enable consumers to reduce demand at peak times. Education for users and new retail supply systems are necessary for these advantages to be realised. Smart meters and their potential benefits are discussed further in section 5.4.

2.3 The future of existing mitigation policies after the introduction of a carbon price

A carbon price will be the main driver of transformation of the electricity sector. The carbon price will alter electricity production and consumption—but it is neutral as to how this change is achieved. In some cases the carbon price may drive deployment of low-emissions generation—large or small scale—or it may lead to fuel switching, or the adoption of more efficient operating practices in various sectors of the economy.

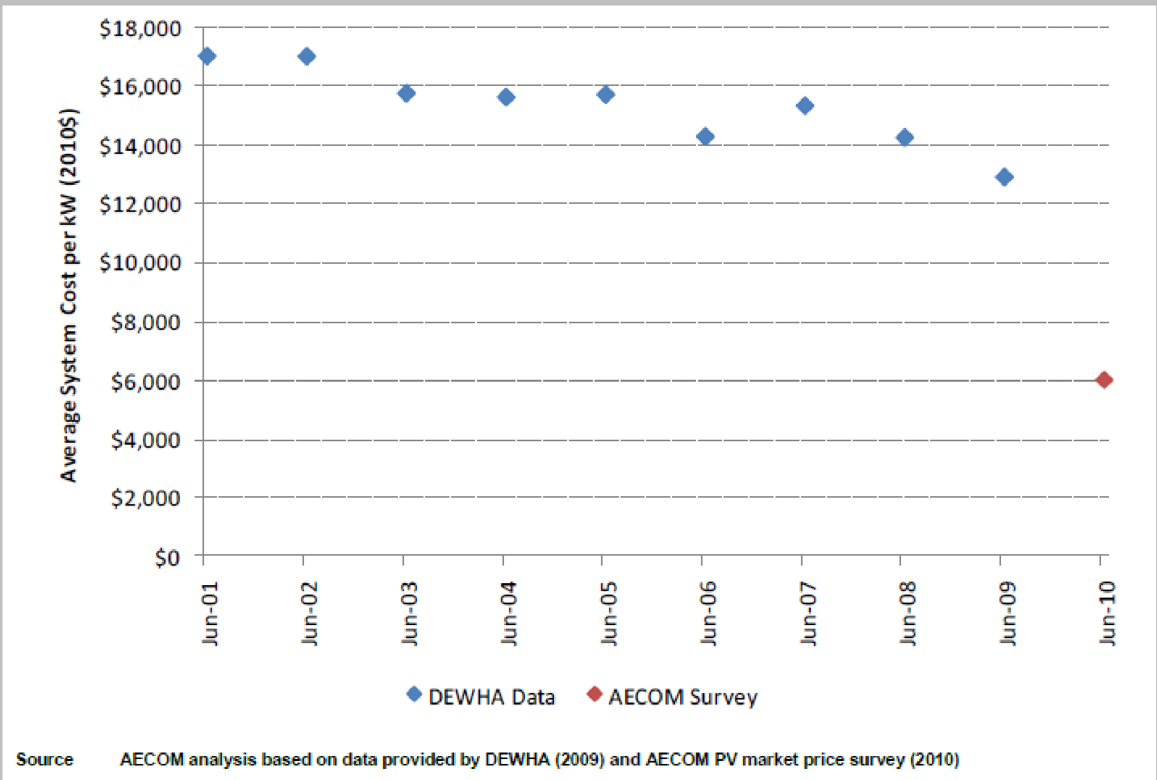
Box 3: Investments in solar photovoltaic

Solar photovoltaic (PV) panels convert solar radiation to electricity. Small, rooftop PV systems have become extremely popular with Australian households. Australia has seen more than a six-fold increase in PV generation capacity over the 2000s—and a 360 per cent increase between 2008 and 2009 (Macintosh and Wilkinson 2010; Wyatt and Wyder 2010). In October 2010, around 187,000 small-scale PV systems were installed, with a total capacity of 301 MW (around 0.6 per cent of registered capacity in the National Electricity Market)(Clean Energy Council 2010).

The economic case for the installation in PV has been made more appealing by falling capital costs and rising electricity prices, and the private commercial case by rich government subsidies.

The capital costs of solar PV systems in Australia have fallen dramatically in recent years, due to falling international PV module pries, a larger and more competitive market, and a stronger Australian dollar (AECOM 2010; Green Energy Markets 2010). In Australia, typical system prices for grid-connected systems of up to 5 kW fell by 36 per cent between 2000 and 2009 (Wyatt and Wyder 2010) and more in 2010. This decline is illustrated below for New South Wales.

Figure 7: New South Wales PV system costs per kW of installed capacity (2010 dollars, excluding rebates)



Source: AECOM (2010).

In 2010 an average benchmark system price for a 1.5 kW system in Australia was around $7,725 (module cost of around $2.15 per watt, and $1,140 for the inverter). Average quoted costs for systems of other sizes are discussed below. The net cost to customers—post-Renewable Energy Certificates or subsidies—have been much lower, and in some parts of Australia a 1.5 kW system can be as low as $2,300 (Green Energy Markets 2010).

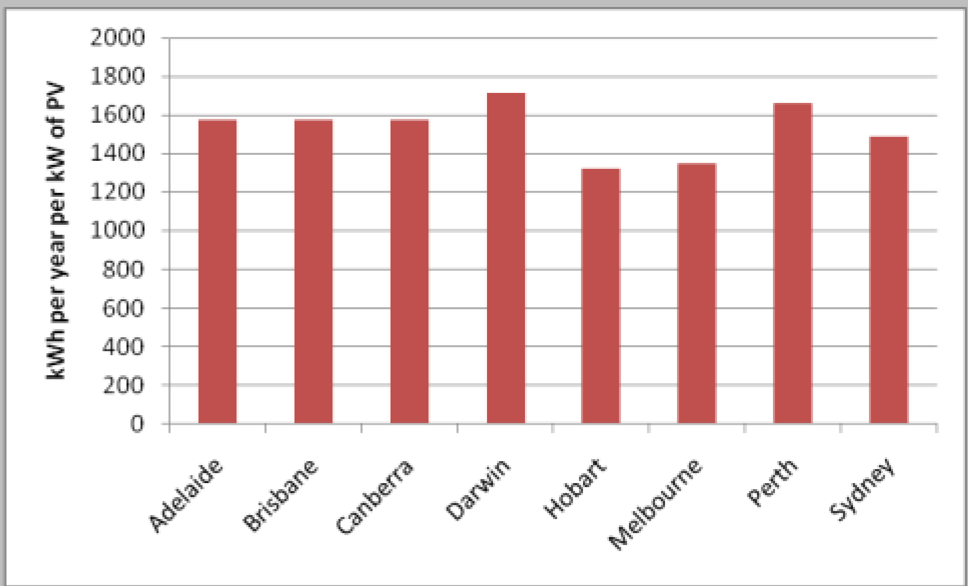
In 2010 an average benchmark system price for a 1.5 kW system was around $7,725 (module cost of around $2.15 per watt, and $1,140 for the inverter). Average quoted costs for systems of other sizes are below. The net cost to customers—post-RECs or subsidies—has been much lower, and in some parts of Australia a 1.5 kW system can be as low as $2,300 (Green Energy Markets 2010).

Total system costs are expected to fall around 10 per cent over the next year, and then decline around 7 per cent each year to 2013 (Green Energy Markets 2010).

Government rebates and market-based support have made solar PV systems more competitive with other forms of residential electricity supply. From the beginning of 2000 to mid-2010, around $879 million (real 2009 dollars) in Australian Government rebates supported the installation of almost 108,000 systems, with a combined installed capacity of 128MW (Macintosh and Wilkinson 2010).

Evaluations have concluded that these subsidies have effectively driven the deployment of solar PV. In terms of energy and emissions reductions, the approach has been costly. The public subsidy cost per tonne of greenhouse gas emissions abated through rebated PV systems is estimated at between $257 and $447 per tonne carbon dioxide equivalent—far above the carbon prices being considered under any proposed model (Macintosh and Wilkinson 2010; ANAO 2010). This cost is not the same as the economic costs of PV systems, which are much lower. Despite the growth of PV in Australia, its impact on electricity demand remains modest. In late 2010, installed PV systems accounted for 0.6 per cent of installed electricity generation capacity, and around 0.2 per cent of 2009-10 output in the National Electricity Market.[3] The output of a system is not simply its rated capacity; actual output a system varies with the amount of solar radiation, a changing temperature and other factors. The typical annual output from 1kW of network connected photovoltaic is illustrated below.

Figure 8: Typical Output from 1 kW of grid-connected PV, installed at the appropriate orientation and inclination



Source: Australian PV Association 2009.

The impact of solar PV on peak demand is even less significant. Studies suggest that the contribution to residential peak demand is limited, because PV output peaks around 1.00pm and output from solar PV is greatly reduced by the later afternoon (Energy Australia 2005). In New South Wales, for example, average output at 5pm is less than 15 per cent of the system capacity (AECOM 2010). This is due partly to the inverse relationship between maximum power and cell temperature (Myers et al 2010).

Under a carbon price, the market, rather than the government, will be making abatement decisions, which will ensure emissions reductions are delivered at lowest cost. The cost of abatement will be lower

[3] Based on figures on installed capacity and output from Clean Energy Council 2010 and figures on National Electricity Market registered capacity and output from AER 2009a.

than the existing climate change policies discussed in Section 2.1, and the overall impact on prices will be more modest than the cumulative impact of existing policies in the future.

With a carbon price in place, current climate change mitigation policies would not be a cost-effective way to reduce emissions. Most, including the Renewable Energy Target and support for household photovoltaics, should be phased out. The deployment of smart meters is an important exception; smart meters, properly used, will complement a carbon price and increase its effectiveness (see Section 5).

3. The risks to energy security in the transition to a low carbon electricity sector

3.1 The transition in electricity generation

Reforms associated with the creation of the National Electricity Market have created a wholesale electricity market in Eastern Australia that is well placed to deal with the change in relative prices that will flow from a carbon price.

A carbon price will change the relative costs of different sources of generation according to the emissions intensity of each.[4] The flexibility of the electricity market allows wholesale prices to adjust quickly to reflect these changes. Most of the carbon price costs will be passed through to consumers. Some generators will find that revenues will rise more than costs. The most emissions-intensive will find that costs rise much more than revenues. Companies with a portfolio of generation assets that is balanced across emissions intensity will neither be big winners or big losers.

The open market for generation capacity will allow new lower-emissions generators to enter the market, according to the price signals, if it is profitable to do so. The dynamics of the National Electricity Market are well established and since its formation, large private investments have been made in new generation capacity to meet our growing energy needs. The market will continue to encourage investment in new generation capacity to meet growth in demand. A recent assessment says that installed and committed generation capacity across the National Electricity Market will be adequate until 2013-14 to meet peak demand projections and reliability requirements, with new generation required after that (AEMO 2010b).

As long as the rules of the carbon pricing policy are clear, private investors will be able to form judgements on the amount of investment in low-emissions generation that is warranted. As with any market, there will be some commercial risk. Just as the uncertainty around forward gas prices affects decisions to build gas driven peaking plants today, uncertainty around forward carbon prices beyond the fixed price period will also be factored into such decisions.

The comparative advantage of different forms of generation will depend on a range of factors, of which a carbon price is but one[5].

The transformation of the electricity sector that is likely to be required has been apparent for some time, and became clearer when there was bipartisan support for a price on carbon following the Shergold Report on emissions trading in mid 2007. Some of the largest and most successful firms in the Australian market have since taken steps to minimise the impact of the transition, and uncertainty surrounding it, through diversification in their generation portfolio and vertical integration to manage the risks between generation and retail operations.

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[4] With a carbon price, the cost of emissions intensive forms of generation like coal will rise relative to those that rely on lower emissions fuels, in particular gas. Zero emissions sources like wind will not incur an increase in costs.

[5] Other relevant factors include the relativities between different fuels, the cost of capital, demand projections, and the likely behaviour of current players and future competitors.

The impact of carbon price uncertainty on investment decisions

While there has been a stable investment environment since the National Electricity Market's inception in 1999, more recent debate over domestic climate change policy, particularly the potential introduction of a carbon price, has created uncertainty for investment in generation capacity.

Both existing and potential new investors suggest that they are encountering difficulties in implementing plans to sustain value in existing generation assets, or to finalise decisions on projects for new capacity. The majority of recent investment has been in gas-fired generation—due largely to the need for peaking plant, as the current generation profile is weighted towards baseload generation (AER 2010a). This has been in an environment of oversupply and low prices for baseload capacity as supply constraints associated with drought have lifted and demand has grown slowly.

Recent analyses have highlighted the possibility that carbon price policy uncertainty may lead to investment in a suboptimal future mix of generation capacity (Nelson et al. 2010; Frontier Economics 2010). In the current environment, investment in coal-fired power, despite being the lowest cost form of baseload generation, is unlikely given its high emissions intensity and subsequent exposure under a future carbon price.

At the same time, investors report difficulties in securing project finance for baseload and intermediate thermal alternatives to coal (Nelson et al. 2010). Investors are minimising risk and therefore capital costs by investing in Open Cycle Gas Turbine technology to meet demand, rather than Combined Cycle Gas technology, which could be optimal under a carbon price. It is worth noting that investors have recently been selecting open cycle gas models that can be quickly adjusted to combined cycle operations (see Origin 2011).

The electricity transformation

Modelling of the electricity sector provides an indication of a possible future mix of types of generation. There are three broad trends that can be expected with the introduction of a carbon price. First, there is likely to be an initial increase in gas generation—gas is likely to displace coal through changes in the intensity of use of current plants at relatively low carbon prices. However, if gas prices rise in Eastern Australia (in line with the expectation that prices will increase towards export parity with the development of an export industry on the East Coast) then the increase in gas generation may be temporarily delayed. The recent experience with high gas prices and the current cost-competitiveness of coal in Western Australia—even with a carbon price around the levels suggested for the early years in Update Paper six (*Carbon pricing and reducing Australia's emissions*)—is an example of the dynamic possibilities that can emerge in a competitive market.

As the carbon price rises with time, and as the costs of newer technologies fall with research, development and experience, less emissions intensive forms of generation will become competitive. The extent of the change after movement to emissions reduction targets and a floating carbon price will depend on the cost of abatement elsewhere in the economy. With the emergence of credible international markets for abatement, the balance between domestic and international reductions in emissions will be determined by factors affecting costs of abatement in Australia and abroad.

As new generators enter the market, supply from more emissions intensive generators will be gradually displaced. As new low-emissions generators enter the market, existing emissions intensive generators can be expected gradually to reduce output.

The Update examined closely the options for emissions-intensive baseload generators to operate flexibly to generate value as the carbon price increases. Within economic limits, there is considerable scope for flexibility. Recent analysis commissioned by the Update has confirmed that even for older brown coal facilities such as Hazelwood and Yallourn in the Latrobe Valley, it is possible for generators to operate intermittently in the summer months to meet demand on hot days (Box 4). In some circumstances these facilities could operate profitably by selling into the market when prices are high.

Box 4: A non-baseload future for brown coal-fired generators

The Update commissioned Sinclair Knight Merz to evaluate the potential for brown coal-fired generators to operate in a non-baseload capacity in the future. The report found that for the Hazelwood and Yallourn facilities, there are no known technical reasons which would prevent the facilities operating in non-baseload capacity—that is, limiting operations to when demand is likely to be high in summer.

The report confirmed that these plants:

- can be completely shut down for a number of months in a year;
- can be recalled from a state of complete shutdown in approximately two weeks;
- can operate intermittently for several days at a time on a relatively short recall period of about three days—a shorter recall period of less than three days could be achieved at added expense; and
- the total maintenance costs would be much lower under such a regime because the plant overall will run less.

More complex staffing arrangements would be required.

This analysis confirms the technical viability of coal-fired baseload plants operating as a plant with intermittent production—as coal-based plants do overseas and have done in the past in Australia.

Source: SKM 2011.

The figures below use two scenarios from the recent modelling results by the Australian Energy Market Operator to illustrate the general story of the switch to gas, the opening of new low-emissions generation and the closure of older emissions intensive generation over time. Figure 9 is based on what the Australian Energy Market Operator characterises as an ‘uncertain world’. The ‘uncertain world’ scenario assumes a 5 per cent emissions reduction target, high economic growth, no available geothermal generation, and low hydro inflows. This scenario shows the highest installation of gas powered generation due to the exclusion of geothermal, lowered access to hydro, and the introduction of a carbon price. The low value of carbon does not provide significant motivation to promote retirements, especially when coupled with the high demand, and therefore emissions remain relatively high.

At the other end of the spectrum, Figure 10 is based on the Australian Energy Market Operator’s ‘fast rate of change’ scenario. The ‘fast rate of change’ scenario assumes high economic growth and a 25 per cent emissions reduction target. This scenario shows significant new base load gas and coal fired generation that makes use of carbon capture and storage technology. The high carbon price results in major capacity retirements, and a substantial level of new renewable generation, particularly wind.

Figure 9: 'Uncertain World' scenario

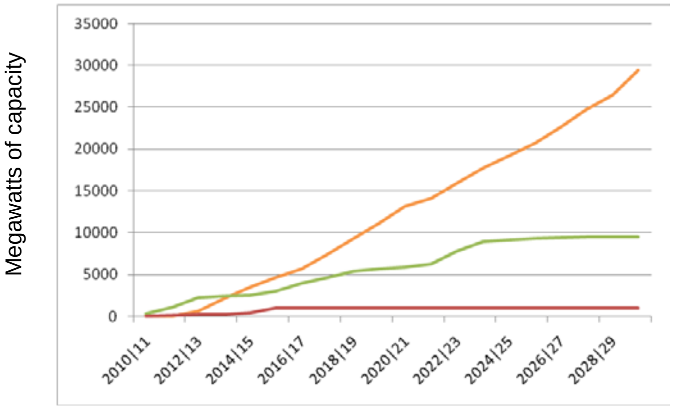
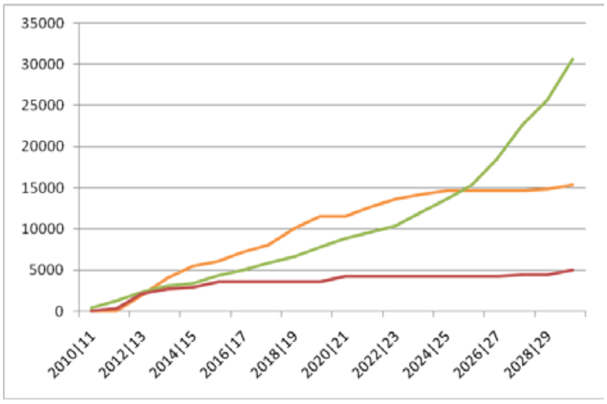


Figure 10: 'Fast Rate of Change' scenario



Source: AEMO (2010).

3.2 The economics of brown coal generators

The introduction of a carbon price will lower the profitability of the most emissions intensive electricity generators. The most emission intensive generators in Australia are the brown coal generators located in Victoria and to a lesser extent South Australia. These generators are large contributors to baseload generation, and this role will be affected for at least some plants during the transformation to lower emissions generation.

Industry analysts suggest there is evidence of some brown coal generators being in precarious financial positions even before the introduction of a carbon price. The industry estimates that over the next five years $9.4 billion in debt on generation assets will need to be refinanced (ESAA 2010). Approximately $6 to $7 billion of debt held by the high-emissions generators in the South Eastern states.

Part of the increase in costs from carbon pricing will be recouped by passing through the price increases to electricity users. It is not possible to say in advance what proportion of the cost increases will be passed on. This is the source of community concern about electricity price increases. For generators as a whole, most of the carbon costs are likely to be recouped from price increases. Community concern for higher prices is the reciprocal of generator concern that they will not be able to pass through costs: in the final outcome, more pass through of costs will ease adjustment pressure on generators and intensify pressure on consumers. Even with high pass-through of costs, as is likely, the introduction of a carbon price will adversely affect the financial position of the most emission intensive generators—those that use brown coal in generation.

When the consequences of changes in cash flows and adjustments to them are worked through in detail, there are financial difficulties for firms to manage, but the risks to physical energy security are low—if not negligible. The National Electricity Market is self-correcting in terms of physical supplies;[6] prices will rise to justify retaining capacity if the alternative is unmet demand. Furthermore, like all dynamic markets, any reduction in supply by one producer will lead to an increase in prices which subsequently increases the profit margin for all other producers. The most emissions intensive plants in each region are likely to be the first to start to reduce their output and this will drive an increase in non-peak wholesale electricity prices. The owners of the next-most emissions intensive generators in a National Electricity Market region will benefit from these higher prices, and thereby be more likely to remain capable of servicing debt and generating a return to shareholders (DCC 2009).

[6] When the system is at the point of shedding load, the price must be set at the price cap of $12,500/MWh. Or, after the equivalent of 7.5 hours of price cap in a week, an administrative price cap applies of $300/MWh.

As in any effective market, prices and expectations of future prices will rise to keep supplies in line with demand and expectations of demand. The owners of even the most emissions-intensive physical generation asset will have an incentive to meet demand at lower output levels, possibly in an intermittent capacity, for as long as there is physical demand for the output at the prices that emerge from the market.

So long as there is a mode of operation at which revenues exceed recurrent costs, the owners of and lenders to emissions-intensive generators have incentives to continue profitable physical operations, the honouring of existing contracts with retailers, and an ability to sell new contracts. This will ensure that the current owners and lenders extract the maximum value from the plant, whatever its future role may be in the market.

Many people in Australia, including many in business leadership roles, distrust markets. They fear that market outcomes will be seriously disruptive, and dislike the uncertainty with which market outcomes are associated. There is a deep Australian yearning for the certainties of controls and subsidies. However, while markets are imperfect, the general experience is that they are more effective than any other mechanisms for ensuring that supply is available reliably to meet demand. I see no reason why the electricity market is different from others.

The recent experience with the parent of a generator may be reassuring to those who doubt the capacity of markets. The collapse of Babcock and Brown did not stop Babcock and Brown Power (now Alinta) from operating in the National Electricity Market.

Analyses of generator viability that do not take into account electricity market dynamics will produce a distorted picture of the internal economics and stability of the market. See for example, the Department of Climate Change's analysis of the Morgan Stanley study undertaken for the Government in 2009 (DCC 2009). It is important to recognise the capacity for generators to move from baseload to intermittent generation when it is profitable to do so. It is essential to recognise that contraction in supply in one plant will increase prices, revenue and profitability in others.

Analysis of market dynamics reveals that the unconditional grant of free permits to generators does not affect any of the influences on profitability and therefore on any of the decisions that will actually determine whether established plants continue to produce power or whether there will be investment in new capacity. On the other hand, conditional grants would distort the adjustment.

3.3 Potential risks to energy security

In the debate around generator compensation, three types of risks have been commonly cited as threats to energy security. The materiality of these risks has not been thoroughly analysed in earlier Australian discussion of carbon pricing.

The question is whether the introduction of a carbon price will threaten the security of energy supply. Past discussion has tended to confuse this concern with other issues.

If there is a lack of clarity around the energy security concern, this will undermine the identification of a logical least-cost means of resolving the concern. In the discussion below, I conclude that two out of the three commonly cited risks are legitimate and warrant a cost-effective government response.

The risk of contract market contagion

While there is an active and responsive physical spot market, transactions for electricity are primarily traded on contract markets. The many participants in the National Electricity Market have opaque contractual relationships. Retailers contract for supply in the event of high demand and thereby avoid the impact of high spot prices. With increased vertical integration, it is likely that the contract market has shrunk in recent years, but the full extent of commitments among parties is unknown.

There is some anxiety that a financial market or contract market shock or sudden unexpected change in input prices or natural disaster or strike could lead to financial contagion, irrational behaviour and threats to energy market stability. The anxiety extends to the financial shock that could come from a participant being insufficiently prepared for the consequences of a carbon price.

If the firm operating a large and emission intensive generator were unable to meet financial obligations as they were due, it may be unable to reach a mutually acceptable agreement in the timeframes available. As a result, the generator would be unable to honour existing hedge contracts to retailers at a time of high spot prices. This unlikely event could trigger a financial contagion precipitating instability within the industry.

It is worth noting that such an occurrence could arise due to circumstances unrelated to the introduction of a carbon price. For example, the worst possible case of contagion risk could have been realised in the Great Crash of 2008 when the operating company of Babcock and Brown Power (now Alinta) collapsed. In that instance, the owners and lenders were able successfully to restructure their financial arrangements over an extended period of time.

There is no established mechanism within the National Electricity Market to deal with contract market instability. This is unlike regulatory arrangements in other markets, notably financial markets, in which large and negative consequences are anticipated from the failure of large firms ('too big to fail'). The electricity market is another area in which a major firm may be thought by some to be too big to fail.

The enhancement of regulatory protections in this area is warranted. However, in line with understanding of best practice in the aftermath of the Great Crash of 2008, it is important that being "too big to fail" does not protect shareholders in large enterprises from the financial consequences of changes in the business environment. The purpose of protective regulatory arrangements is to enhance the wider community interest. Any protective measures should secure the community interest in market coherence at the least possible costs to the community.

The prospect of suboptimal maintenance of generation assets

Some electricity sector stakeholders have suggested that energy security or reliability concerns may arise from weak incentives for firms adequately to invest in maintenance as they approach the end of economic life.[7] It is feared is that this could lead to sudden decommissioning of all or part of a major plant and to disruption of supply. If the only available replacement before new capacity comes online—perhaps the more intensive use of a plant designed for peaking—is higher cost generation, this could result in sustained periods of higher wholesale prices.

These circumstances could possibly arise with the introduction of a carbon price although, as I have indicated above, it is unlikely. To the extent that the concern is valid, it is more general. The same concern could arise independently of a carbon price, as a number of large baseload generation assets approach the end of their economic lives in the coming decades and are vulnerable to the financial stress of an owner. The Australian electricity market has never yet had to deal with large amounts of capacity being withdrawn from the market, with small plants being replaced by larger plants. The market has a number of ageing assets and in the future large plants would need to be replaced, thus raising issues around smooth transition.

There would be value in removing these concerns by augmenting the regulatory framework to deal with the increased risks of supply disruptions as plants approach their end of life. However, the incentives to minimise operating expenditure and delay capital expenditure on maintenance will be balanced by market incentives to continue profitable operations. Plants which cut back on maintenance levels will face higher rates of disruption, which will in turn reduce their ability to carry long-term contracts (the

[7] Faced with large maintenance outlays and limited prospects for future revenue, owners will rationally cut back on maintenance and accept a higher risk of outage which will be traded off against the value of peak capacity. This is an intended outcome.

primary source of commercial value for all generators). Given the market incentives to undertake the appropriate level of maintenance, a light handed regulatory approach is preferred in the first instance.

Investment in new capacity

I explained in 2008 that the impact of government carbon pricing policy on the value of assets (also known as asset impairment) is not an issue in and of itself.[8]

The provision of capital grants to generators will not affect the incentives that drive electricity prices or investment decisions. Markets are well equipped to manage the financial stress of one or more participants.

In consultations with the Update, generators have focussed less on demands for capital grants than they did in consultations for the 2008 Review, and have focussed more on requests for government to pay for closure of high-emissions plants. Some have argued that plant retirements should occur with ‘reasonable periods of warning’ so that replacement plant could be planned and constructed (ACIL Tasman 2011). This is predicated on the assumption that otherwise plants will leave the market abruptly, leaving a shortfall in unmet demand. This is not how dynamic markets like the National Electricity Market work—nor the way that global markets for commodities or industrial goods work. While the ownership and financial arrangements of a plant may change, the plant will continue producing—perhaps with gradual reduction in output over time—while it is profitable to do so. This means that the plant will continue in operation until ceases to be required to meet demand at prices that are expected to clear the market.

If there happens to be a low appetite for capital investment in Australian electricity generation, the wholesale price of electricity will rise accordingly. This is a predictable and ‘bankable’ feature of the National Electricity Market which private investors will anticipate. In the end, the market might commence new generation a bit early or a bit late—during which prices may be temporarily depressed or inflated. This is normal for markets. In the electricity market too, imbalances between supply and demand will lead to changes in prices and expected prices which lead to adjustments that move supply and demand back into balance. It is incumbent upon those who argue that the electricity market cannot be trusted to bring supply and demand into balance, to show analytically how the electricity market is different.

Box 5: Emergence of electricity generation-retail integration and competition policy

The original design of the National Electricity Market was based on structural separation of generators from retailers, but in recent times there has been a clear trend towards the emergence of generator-retailer businesses — starting with AGL’s purchase of a stake in Victorian Power Station Loy Yang A in 2004. Vertical integration allows retailers to manage generator risks internally and reduce transaction costs, but can also undermine market competition, particularly if there is a loss of liquidity in contract markets. This has been observed in New Zealand where dominant regional generator-retailers have emerged and reduced the prospects for retail only businesses (Willet 2008).

The successful purchase of New South Wales retail businesses and generator output by two of the three large generator-retailers (TRUenergy and Origin) has resulted in further market concentration.

The potential for anti-competitive behaviour in these circumstances has been investigated by the

[8] In the same way that government is not expected to attempt to extract the gains from policy change, industry should also not expect government to socialise the losses in the case of electricity generation assets. There have been times in the past , unhappy for Australian economic performance, when there was an expectation that Government would socialise losses but not gains from policy and other changes. There have been elements of this approach in the recent discussion: calls for compensation of losses from carbon pricing have not been accompanied by suggestions that these should be paid for by levies on gains for low-emissions producers generated by the same changes.

Australian Energy Regulator but to-date no such breach of rules has been found. Nonetheless risks to competition may be emerging. The National Electricity Rules leave regulation of anti-competitive conduct to the Trade Practices Act but it is unclear if the relevant Section 46 provisions can be readily applied to the type of market power impacts that are present in the National Electricity Market (Willett 2009).

It is in this context of consolidation and integration, coupled with restrictions on the expansion into retail of some generators by their state owners, that the value of a ‘Pillars’ policy in the electricity sector has been raised with the Update. Australia’s ‘Four Pillars’ policy, which disallows mergers between the major banks, is thought to have effectively balanced competition and stability concerns in Australian banking. In electricity with increasing vertical integration competition will require the operation of a minimum number of firms in each regional market. This would be achieved more readily with greater inter-connectivity between state markets. It would be assisted if two or more substantial publically owned entities, including Snowy Hydro and Hydro Tasmania, were freed by their owners to operate commercially in a national market. Ideally the latter development would be associated with sale of equity into private markets. The ‘Five Pillars’ would be free to expand through merger and acquisition except in relation to each other.

I recommend an independent review of competition in the electricity sector. This could include examining the benefits of removing restrictions imposed by state governments on the expansion of state owned generators into retail services – the development of additional pillars. It should also cover the extent to which greater connectivity across the National Electricity Market might serve to promote competition in a more consolidated and integrated environment.

3.4 General measures to enhance the stability of the National Electricity Market

The Energy Security Council

The sudden failure of a larger generator could confer damage on the wider economy if it led to disruption of financial arrangements among market participants more generally. The National Electricity Market lacks arrangements to interrupt financial failure contagion between large interdependent participants. It is appropriate to introduce a mechanism to minimise the perceived financial and contract market threats to physical energy security and reduce the risk of a high cost ad hoc government response.

The government proposed in 2009 to introduce an Energy Security Assurance Mechanism (DCC 2009) in the context of the then proposed Carbon Pollution Reduction Scheme. I support the introduction of an Energy Security Council with the role of governing a mechanism that is analogous to the Energy Security Assurance Mechanism. This should be a general regulatory enhancement of the National Electricity Market. The case for this mechanism does not depend on the introduction of a carbon price, as it is designed to deal with contagion risks that may arise from several causes.

The establishment of an Energy Security Council could enhance existing regulatory arrangements and provide governments with a mechanism to respond to financial and contract market instability and contagion risks. Consistent with the proposal in 2009, the Energy Security Council would include experts from fields of business, public finance, insolvency and the energy market (DCC 2009).

The Council’s terms of reference would require it to act only as a last resort to avert contagion. The Energy Security Council will not remove risk from individual participants, directly protect customers or provide compensation to equity holders[9]. This avoids moral hazard influencing the behaviour of market participants.

The Council would respond when approached by a participant, government or customers concerned about its own or another's financial situation. The distressed party could be any market participant (generator, retailer, or trader). There would be a strong incentive for a distressed party or its counterparty to voluntarily approach the Energy Security Council about an apparent financial weakness, in advance of its manifestation of incapacity to meet financial obligations. Retailer counterparties would have an interest in alerting the Council if a generator dishonours or is in danger of dishonouring a contract.

The Energy Security Council would be authorised by Government to undertake a range of rapid interventions to stabilise the market. It would have a number of instruments at its disposal, including short-term loan guarantees. As speed is required, the provider of the financial response would need to be the Commonwealth Government. However, as the distressed participant is likely to have its business in mainly one or two states, there is rationale for the state governments to participate in any longer-term arrangement.

Improved market monitoring

Australian Energy Market Operator currently monitors forced supply disruption rates and reports on minimum reserve requirements in the National Electricity Market. It would be prudent for the relevant Australian Energy Market Operator working group to reconsider the adequacy of current risk-monitoring and reporting frameworks.[10] For example, the reliability data from generators may need adjustment to be more timely and more accurate in a period of changing operations.

Measures to encourage contract market stability during the introduction of a carbon price

As discussed earlier, generator insolvency could lead to a broader range of knock-on effects which result in contract market instability and contagion. The Update's assessment is that this risk is quite small and that the strengthening of the regulatory framework represented by the formation of the Energy Security Council is a sufficient response to the risk.

Nevertheless, it is clear that the proposed Energy Security Council will leave some anxieties. I propose a cost-effective way of providing additional comfort.

I acknowledge that the consequences of a major financial dislocation could trigger contagion in the electricity market. I therefore suggest a measure that is directly related to the problem. A financial market failure requires a financial market solution.

The proposal would only lead to expenditure of public money in circumstances in which such expenditure is warranted by specific market developments. The public finance cost would relate to the difference between the economic value of the guarantee and the fee that was applied to the guarantee. Alternatively, and, if the sums are done correctly, with a similar outcome, the cost is the product of the amount of money that might be lost and the probability of loss, less the expected present value of the guarantee fee. The arrangement would only lead to the actual outlay of public money in circumstances in which those outlays were directly related to the restructuring of an emissions-intensive generator. It would involve substantially lower commitments of public funds than the grant of free permits at levels involved in the final version of the proposed Carbon Reduction Pollution Scheme in 2009. Unlike the 2009 proposal, it would directly affect the financial market problem that is the reason for the intervention.

[9] If a retailer fails to provide collateral to AEMO during high prices, its customers will be transferred to another retailer performing the Retailer of Last Resort function. ESAM should not seek to protect customers from being transferred to other retailers.

[10] With members from the AER, generators and network businesses.

With the renegotiation of debt arrangements for a period commencing with the announcement of a carbon price, there is likely to be a transitional period in which there are larger than usual risks that the Energy Security Council will be asked to intervene.

I propose a temporary Energy Security Loan Guarantee to address the transitional risk in a focused and cost-effective manner. The loan guarantee would be directed to the most emissions-intensive generators. It would be limited in scale and duration. It would designed so have as close as possible to zero influence on the production decisions of owners and lenders.

A government loan guarantee on the debt of generators will have the effect of reducing the short-medium term probability of generator insolvency first of all by strengthening creditor confidence. There are well known examples of one nervous bank within a consortium causing or going close to causing a commercially sound arrangement to unravel. The loan guarantee facility will reduce the probability of such behaviour interfering with the adjustment to a carbon price.

In addition, a government loan guarantee will allow incumbent generators to refinance their generation assets at a lower rate. This will increase the chance of generators refinancing their assets on terms which maintain positive cash flows after payment of interest.

The Energy Security Loan Guarantee could be available to the small number of the most emissions intensive incumbents.

Necessary constraints on the key parameters of the loan guarantee

One main parameter for the guarantee is the proportion of existing debt that will be secured by the Government. The higher the proportion, the more attractive it will be to the creditors and the lower the cost of capital will be for the asset owners. The main constraint should be a limit on the maximum proportion of loans covered by the guarantee (say 75 per cent) to ensure that the creditors always have skin in the game and thereby to constrain moral hazard.

In addition, the Government would set a cap on the loan guarantee—the guarantee should not be extended to any new debt if it would lead to the amount of guaranteed debt exceeding 75 per cent of the debt exposure on eligible projects as at 1 January 2011.

The guarantee is intended to deal with the transitional risks to energy security and therefore should be limited in duration. The scheme should commence before a carbon price. It should only be available to applicants for 2 years from the date of commencement, with all guarantees expiring within 7 years of scheme commencement.

Approved loan guarantees should not be transferrable between business owners in the event that the generating asset changes hands, other than for investment by a new owner on the site of the original project.

Existing generators may wish to scrap an existing generation asset and replace it with another plant in the same location. This would allow the incumbent to re-use its existing connection infrastructure and other local assets. The incumbent would be allowed to carry over the terms and conditions of its existing loan guarantee at the time of restructuring or decommissioning an old plant to help finance the new generation asset.

In providing the guarantee, government would require payment of a fee. It is desirable in the circumstances for this to contain a small concessional element. The fees charged under the Government's guarantee of deposit-taking institutions suggest 100 basis points is an appropriate starting point.

In setting the guarantee, provision should be made for the government gradually to price the facility out of the market. A rate of increase of 25 basis points per annum should provide incentives for generators which remain in operation to switch to wholly private finance over time when they are able to do so.

Additional conditions and arrangements for when the guarantee is called

The Government only assumes the debt if some basic conditions are met by the generator. First, the Government would make payment of its fee a condition of the ongoing guarantee. Second, the generator must maintain its registration in the National Electricity Market. Any conditions which undermine the absolute value of the loan guarantee should be avoided. Third, the Government may require early notification of the possibility that the guarantee will be called.

In the event that an approved applicant decides to call on the loan guarantee, the transfer of debt would be arranged in a way that avoided legal insolvency. Rather, the guarantee should be structured in such a way that allows government to assume the agreed portion of the outstanding private debt obligation by buying out other creditors.

Box 6: An alternative: Contract for Closure

One proposal for energy security that has been proposed in the Update's consultations with industry is for the Government to provide cash to emission intensive generators in return for closure. It is attractive for high cost generators because it provides cash to their creditors and owners. It is attractive to the creditors and owners of other generators because it will lead to higher electricity prices from which all generators benefit. It is not attractive to electricity consumers.

If such an approach were to be pursued, the preferred approach would be to conduct an auction for reduction of production over time (Megawatt hours of generator output). This would allow high emissions generators to operate flexibly and would allow economically efficient adjustment from baseload to intermittent operations. A payment to close down capacity completely would preclude efficient restructuring along these lines.

It is usually proposed that the identification of plants for closure would be made through a reverse auction.

One issue with the Auction for Closure mechanism is that it is highly dependent on the strategic behaviours of the participants in response to the various elements of auction design. The challenge in designing and successfully executing such an auction cannot be understated.

The Auction for Closure requires the certain payment of cash but this is not the main cost. Electricity prices will rise as a result of the closure of capacity. This increase in electricity prices is likely to be a much larger cost to the community than the payment for closure itself.

The Auction for Closure requires government to prescribe the natural pathway to market exit. Those bidders successful at the auction will be constrained in their ability to respond to changing market conditions such as higher gas prices, lower capital costs for low-emissions technologies or strong demand growth. Government is poorly place to make decision of this kind.

The main benefit of the Auction for Closure approach is that it tells potential investors in low-emissions generation that future electricity prices will be higher. It is not clear that this is necessary. Firms are making their own judgement about the likelihood of high emissions generators reducing their production, and about the effect that this will have on electricity prices.

The choice between removing Megawatt hours of production and Megawatts of capacity has large implications. The removal of Megawatt hours of production is much preferred, as it preserves the potential economic value of intermittent production.

4. Electricity infrastructure to support the transition to low emissions

The 2008 Review made a number of policy suggestions relating to the interaction between climate change mitigation policy and the transmission and distribution network.

Following a significant review of electricity market frameworks in light of climate change (AEMC 2009a) and various other policy processes, significant progress has been made in the main areas highlighted by the 2008 Review.

In addition, work is under way in a number of other relevant areas, including a number of ongoing reviews by the Australian Energy Market Commission. Extension of policy development in the directions of recent years can facilitate a smooth transition to a low-emissions electricity sector while helping to contain costs.

4.1 The future of the transmission network

As outlined in the 2008 Review, climate change policy will have profound impacts on the composition of future electricity supply. Putting a price on carbon, as well as other policies such as the expanded Renewable Energy Target (the role of which should be phased out as the carbon price rises) will change the underlying economics of generation, particularly given the differences in carbon intensity among coal-fired generation, gas-fired generation and renewable generation. This is likely to result in changes in dispatch, generation location, exit and entry decisions, and affect the prevailing network flows (AEMC 2008a, AEMO 2010d; Frontier Economics 2008).

The next two decades in Australia are likely to see large quantities of investment in combined-cycle gas turbines; peaking open-cycle gas turbines with lower capital but higher fuel costs; and wind generation (AEMO 2010d). Although presently more expensive, cost reducing technological change and learning may together with a higher carbon price bring on large quantities of solar and geothermal generation. We may see the development and connection to Australia of unexploited hydro-electric resources in Papua New-Guinea. As discussed in Update Paper seven (*Low-emissions technologies and the innovation challenge*), the costs of solar thermal and solar photovoltaic are expected to fall at a faster rate than expected in the 2008 Review, reflecting powerful international developments. A range of other prospective, but speculative, technologies may play an increasing role later in this century. In turn, these sources may also create new opportunities for growth in some existing technologies, such as flexible peaking capacity and energy storage in response to more volatile prices due to the intermittency of wind and solar generation.

In addition to adjustments to the electricity grid required to accommodate changes in the composition of future electricity supply, other large-scale upgrades to transmission infrastructure are under consideration. These include inter-state links that would have important implications for the current market and regulatory structure.

The changes in generation have different impacts upon, and will require different characteristics of, the network. It is extremely unlikely that we could now plan a network that we would consider optimal a few decades from now. The imperative therefore is to anticipate where imperfections in the planning and funding framework might inhibit the network from effectively adapting to a changing future. The newly created National Transmission Planner is a step in the right direction.

The regulatory frameworks for the National Electricity Market can contemplate a wide range of network extensions, and recent and upcoming changes are steps in the right direction. However, the framework does not yet facilitate the development of a truly national network, and there are strong biases against inter-state flows.

There would be large advantages in developing a truly national electricity market—excluding Western Australia and the Northern Territory for the time being, pending economic justification for the connections. Extension of the grid is the key to developing that national market.

Box 7: National Transmission Network Development Plan: scenarios of the future National Electricity Market

The National Transmission Network Development Plan explored a wide range of potential scenarios as part of its analysis of Australia's electricity transmission network needs over the next 20 years. The scenarios modelled ranged from a high growth, high carbon price scenario (fast rate of change) to a low growth, low or no carbon price scenario (slow rate of change). Below are some key outputs of these scenarios:

	"Fast rate of change" 15% target	**"Uncertain world" 5% target**
National Electricity markets emissions:	168mt in 2030	215mt in 2030
New renewable generators:	10,700MW	9,500MW
New conventional gas gens:	18,600MW	29,400MW
Gens with carbon capture:	12,950MW	Nil
Coal Retirements:	4,451MW	1,004MW
Generation Capital Expenditure:	$74b	$68b
New Transmission:	$8b	$9b

The scenarios show the great spread of potential generation developments that might accompany various economic, policy and technology drivers. They also show that with the right policy settings, substantial emissions reductions can be made with relatively moderate increases in generation cost. As transmission investment costs tend to be small compared to generation costs, it is likely that there will be substantial option and other value from effort expended now to prepare the transmission network and make it flexible to accommodate a broad range of these scenarios.

Source: AEMO 2010a.

4.2 Possible future network extensions

This section introduces some examples of large scale network upgrades which have been identified in our discussions with stakeholders for the purposes of illustrating what might develop in a low emission future. They demonstrate the issues that a sound regulatory framework has to be able to manage.

Point-to-point projects

Point-to-point projects can connect remote but geographically concentrated sources of new generation to customers, but are unlikely to provide a conduit for other generators along the route.[11] The projects' prospects are therefore linked to the future economics of that generation, in competition with others. Private sponsorship of the connections by the developers themselves seems appropriate. These are allowed by the existing arrangements for lines with purely point to point characteristics, without opportunities for multiple uses, it is appropriate for the private developers to carry the costs and absorb the benefits as they would from the new generation capacity.

Examples of point-to-point projects include connections between the Cooper Basin and the National Electricity Market to connect potentially large renewable energy resources. It may be possible to provide, in stages, up to 5000 megawatts of connection capability at a current cost of $3.5 billion or $0.7million per Megawatt (AEMO 2009a) using direct current. If geothermal generation or other suitable renewable sources (such as solar thermal) were to achieve technological breakthrough such that its installations costs became low and less remote sources are not discovered, then this cost could be justifiable.

Multi-purpose extensions

Some long extensions attempt to capture multiple benefits, typically through the use of a line that can, in the future, pick up customers or generators en route or through small extensions of the line. Whilst it is appropriate for the main proponent at the end to sponsor the line according to the size it needs, there may be long-term economic advantages if a more expensive design is pursued at the outset, which contains the flexibility for future connecting generators. It is unreasonable to require the original sponsor to fund this additional cost. Instead, the additional cost should initially be recovered from customers more generally, and then recouped from the connecting generators when they ultimately use the capacity. Bringing together a right-sized multi-purpose extension will be challenging. It is likely to require a changed approach to planning and network regulation such as the use of “Real Options” valuation. The proposed National Electricity Market Scale Efficient Network Extensions arrangements seem capable of efficiently facilitating incorporation of the option value of uncertain future developments.

A good example is the comparison of ways in which the mining centre of Mt Isa, with a load of around 400 Megawatts, might be connected to the National Electricity Market. The CopperString project currently being studied proposes to connect the mines around Mt Isa to the National Electricity Market with 1000km of alternating current lines at a cost of over $1.5 billion, whereas a single purpose 400Megawatt direct current line would cost only $1.0 billion (Roam 2009). The Copperstring proposal would have the advantage of providing a conduit for the connection of possibly 1000 Megawatts of renewable generation along its length, an area of interest as it has high solar insolation (Copperstring 2010). The economics suggest that this additional cost of alternating current could be considered against the real options value of its possible future benefit. If it is worthwhile, then it is appropriate for this additional cost to be borne by the generators when they ultimately connect, but in the meantime, by consumers more generally.

[11] These high voltage direct current projects have much lower costs per km, but require very expensive converter stations at each point of connection. Therefore they are unlikely to be useful for other benefits, such as picking up generation or load along their path, or the removal of constraints within the existing network.

Inter-state links

Interconnectors optimise the total generation supply by enabling more transfer of energy between the major generation and demand centres. While in themselves they are expensive, they could generate high value from several sources. They allow reserve sharing; thereby reducing the total capacity installed to meet reliability requirements. They increase competition everywhere by increasing the number of generators which have access to each market. They enable investors to consider a broader geographic scope when developing low-emissions projects. And they provide more places to connect future generation, including from low-emissions sources. Judicious placement of additional inter-state connections can increase the opportunities for new sources of power.

A recent prominent example of a large scale interconnector project is NEMLink—a $8.3 billion backbone from South Australia to Queensland with an additional cable to Tasmania—which was mooted in the 2010 National Transmission Network Development Plan (AEMO 2010c). This would allow a truly national grid to form, with sharing of reserve capacity and a conduit for the connection of inland wind and solar generation. NEMlink was not justifiable in the short-term, but it came close to break-even in the strong carbon price scenarios from 2021. Whilst a stronger economic case is clearly required, it provides a vision of National Electricity Market with strong inter-state links.

The immediate expansion of inter-regional capacity from South Australian to Victoria and/or New South Wales—where current interconnectors are often constrained—is being considered (ElectraNet-AEMO 2011).

4.3 Towards a national electricity market

There are distinct electricity markets in each state of the National Electricity Market. The interconnectors between them frequently constrain interstate movements, and prices diverge. Investments to supply an interstate market are inhibited. While there may be price divergence between regions in an efficient market, the price differentials are large by any standards. The cost, risk and facility of transition to a low-emissions economy would be improved if the transmission network of the National Electricity Market were enhanced to support a truly national market. Benefits would include:

- Providing a greater geographical scope for low-emissions generator investors to select their ideal location, and many more places to which they can realistically connect;
- By extending across a larger area, more diversity from intermittent solar and wind resources can be achieved, and also broader access for the flexible hydro generation sources in Tasmania, Victoria and New South Wales to back up the variations;
- Greater sharing of generation reserves, requiring less total generator capacity to meet diverse demand peaks;
- Enabling the market to find the most efficient source of power in a national context when a carbon price is taken into account. A high emissions plant is less likely to be required to support local demand peaks;
- Providing a transmission network and market that is capable of withstanding the early retirement of carbon intensive generation without physical or financial shocks in regional markets; and
- Providing for more generation competition, bringing customer prices closer to an efficient level, and improving market conditions for smaller, specialist retailers.

Some point to point and possibly multi-purpose transmission augmentations may be accommodated under current or proposed frameworks. However, the planning framework needs to be improved to allow economically more efficient levels of inter-state connections to be developed.

Some recent enhancements to the regulatory framework for planning transmission are useful on the path to a truly national grid, but need to be utilised more fully by the transmission planners. A transmission asset must be justifiable under a regulatory assessment known as the Regulatory Investment Test before it can be built. Once it has been certified to have passed this test, the costs of those investments including a specified rate of return on investment are passed on to customers. The assessment is based on sound economic principles, allowing the proponent to present a wide range of demonstrable benefits across the electricity industry, including minimising the costs of an anticipated carbon price (AER 2010b). Transmission planners may include:

- Competition Benefits: Transmission benefits consumers through greater competition between generators, thereby bringing wholesale prices closer to efficient costs. This competition can counteract some of the increase in electricity prices from other causes. While the Regulatory Investment Test has been able to take these benefits into account for a number of years, they have never yet been part of a successful justification for transmission investment. Here the problem is not with the regulatory framework. It is with the transmission planners. It seems that planners with engineering backgrounds struggle to allocate value to a rather intangible source of value—competition. It is noteworthy that while the South Australian electricity market is recognised as having a problem of inadequate competition, and while there are relatively low-cost opportunities for expanding South Australian connections, no assessment of the case for expanding interconnections to South Australia has ever attempted to quantify competition benefits. The underutilisation of opportunity within existing regulations could be corrected through the National Transmission Planner, residing in Australian Energy Market Operator, leading the development of a national approach.

- Real Options Analysis: When considering a grid extension to a location, it can be worthwhile building it in a somewhat more expensive way to enable the connection of other, as yet uncertain, low-emissions generation at some future time. This is an example of real options analysis, which is increasingly being applied to policy and planning in scenarios characterised by uncertainty (see HM Treasury and DEFRA 2009). The Regulatory Investment Test allows planners to justify investments using this technique (AEMC 2009b), but they have not yet done so. Box X discusses the history of real options analysis in transmission planning.

Box 8: Real options analysis in transmission planning

Transmission lines are far cheaper and quicker to construct if provision for them is made by far-sighted planners well in advance. One reason is obvious: if easements are acquired before an area is densely populated, future lines can be installed much more cheaply and are therefore more readily justified.

Another reason relates to engineering economies of scale. When lines are proposed, only a small capacity is initially required. For example, sufficient capacity may initially be provided by a single 330 kiloVolt line. As usage grows, the line would need duplication. By investing slightly more at the initial stage, the line can be built ready for expansion, thereby greatly reducing the construction time and overall costs for an expansion at a later date. The initially redundant investment might include building towers capable of carrying a second line to be strung when the need arises, or towers tall enough to carry 500 kiloVolts.

Recent major projects have benefited from the foresight of the planners from the 1960s and 70s[12]. However, despite the later benefits, this practice suffered criticism in the subsequent decades for being economically wasteful. Undoubtedly there were examples of waste. Real Options theory has fortunately allowed us to go beyond slogans and dogma, and to apply a disciplined economic framework within which the value of such early groundwork can be quantified.

[12] For example, NSW transmission's largest project, the "Western 500kV Project" took advantage of such foresight by upgrading 330kV lines to 500kV (Transgrid 2009).

New approaches

Some recently developed changes in the regulatory framework are steps in the right direction (e.g. Scale Efficient Network Extensions). However, the framework does not yet facilitate the development of truly national transmission network, and biases remain against inter-state connections.

The prime symptom of the suboptimal development of the national grid is the lack of long distance, inter-state links, at the same time as inefficient over-expenditure on local transmission and distribution continues to be justified by supplying the extreme peak with reserve capacity. When congestion arises, the National Electricity Market rules favour intra-state flows over inter-state for a number of reasons, discussed below.

1. A fully empowered National Transmission Planner

In 2008 I acknowledged the creation of the National Transmission Planner Role as a positive step. It released its first plan in 2010 (AEMO 2010d). However the National Transmission Planner has no power to actually develop projects. Instead its plan is presented purely as a guide to the state based planners who are free to ignore it.

It seems highly unlikely that a seamless national network can be built by five state-based transmission planners with parochial responsibilities. The crucial next step in transmission reform is the rationalisation of National Electricity Market transmission planning. It would not be productive to seek to merge the existing network owners, whom are partially privatised (AER 2010a). I recommend instead that the National Transmission Planner assumes all National Electricity Market transmission planning. This requires each state to separate its transmission ownership from its planning. The Victorian experience[13] shows that the separation is feasible, and has advantages.

2. National charging for transmission

Identifying specific users of electrical network equipment is difficult and often impossible, so charges tend to be socialised. Some of the value of access to a network derives from its availability and not from the number of electrons flowing over the wires, which is a special complication in assigning value to users. In the National Electricity Market, costs for the shared transmission network in each state are smeared across the customers within that state. An interstate line is funded by consumers in each of the states through which the line travels. This raises obvious questions of fairness when customers in one state must fund part of an interconnector that primarily benefits customers in another. A good example is the investment in export capacity from South Australia to allow the sale of their wind surplus to other states: should South Australian customers fund assets enabling their generators to find customers elsewhere? It is therefore not at all surprising when the funding of greater interstate connectivity is politically contentious. The political issues are especially difficult when the transmission firm is state-government owned.

The problem has been recognised and an incremental solution proposed: inter-regional transmission charging (AEMC 2009a; AEMC 2010b). This requires network companies to charge each other small fees when actually exchanging energy.

However, these minor transfers are not sufficient to correct distortions when considering projects of national significance, in which large amounts of money need to be spent long before flows actually occur, and the cost burden falls unequally. The sound approach is for future transmission planning to be conducted nationally using consistent approaches, without any local allocation of costs. Consistent with my recommendations for national planning and reliability standards, discussed below, the costs of all new interstate transmission should be recovered nationally. All users of power in the regions covered

[13] Victoria has a private transmission network, but planning is carried out by a not-for-profit agency, AEMO. New transmission projects are competitively tendered and not subject to economic regulation.

by the National Electricity Market would receive benefits from access to a smoothly operating market, wherever they were located within the market.

3. State reliability standards

The Regulatory Investment Test permits a departure from a true cost/benefit analysis where necessary to meet a state-based reliability standard (AER 2010c). These local standards tend to be based on historic engineering approaches (see Box 9). They are conservative, leading to economically excessive investment in shoring up local customer reliability. Local over-building undermines the benefits of building nationally.

Box 9: How state-based transmission reliability standards undermine the national grid

Each state has its own transmission reliability standard (AEMC 2008b).These standards are being used to justify almost all investment in transmission, which is running at $1.6 billion per year (AER 2010a). These standards are approached from a purely state-centric view. Interstate connection can also shore up reliability, but this must be valued economically in a rigorous way, based on dollar values of the impact of blackouts. If a state standard is conservative, investments in intra-state networks will proceed beyond an efficient level. This in turn reduces the dollar value of interconnection. This factor was influential in the National Transmission Network Development Plan not justifying economically any major inter-state links in the short-term (AEMO 2010d).

The Australian Energy Market Commission has recognised that the state-based approaches are inconsistent and sometimes have no basis in economic principles. It has recommended harmonisation of the standards (AEMC 2008b). This would only solve the problem if reliability benefits were measured in comparable ways.

4. National Electricity Market congestion management

Although the National Electricity Market is thought of as five pricing nodes, in truth it is a complex network of lines which have been arbitrarily divided along state boundaries into pricing regions.

Generators receive and retailers pay their own state’s price. Trading intra-state is simple. It is possible also to trade between states by using a Settlement Residue Instrument (AEMO 2010c) which offsets inter-state price differences. However, the performance of these instruments is affected by National Electricity Market rules in a process known as “disorderly bidding” (AEMO 2010c, AER 2010c). As a result, inter-state trade in the National Electricity Market has become difficult.

This problem is being studied in the Australian Energy Market Commission’s Transmission Frameworks Review (AEMC 2010c). However, its resolution faces strong parochial interests in the states, supported by vested interests which see themselves as receiving benefits from state protection and the absence of effective national competition. It is important that this matter be quickly resolved.

5. Providing information for an options value approach for inter-regional projects

The first National Transmission Network Development Plan considered the concept of NEMlink (AEMO 2010d). The consideration was only at a conceptual level. The conceptual national transmission network could, with better congestion rules, give the National Electricity Market a national character. It could at the same time pass close to areas of high wind, solar and gas and geo-thermal prospectivity, thus reducing the costs of bringing them into the national market. NEMlink therefore would provide multiple benefits. It is not the cheapest way to deliver any one of them, but may well be the best way to deliver all of them.

There is no case for NEMLink proceeding until the economic case has been made. However the challenge is to ensure that the concept is fully understood, and that all the possible benefits are quantified and brought to account within a rigorous framework.

The cost and construction time for NEMLink could be greatly reduced if small steps toward it were taken early. This might include, for example, the acquisition of easements and the gaining of environmental approvals. It may be that disciplined use of the Real Options valuation approach would suggest early building of elements of NEMLink, to meet shorter term, lesser, transmission requirements.

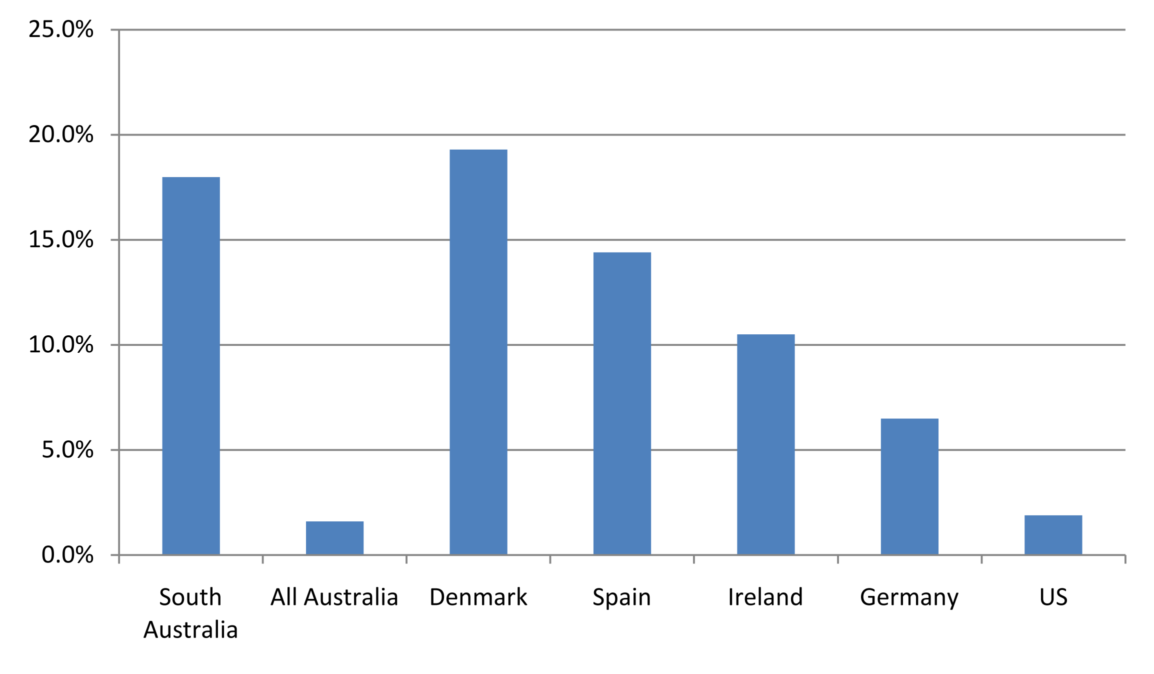
However, this would only be possible if there was sufficient information on which to base such calculations. A much more detailed design of NEMlink is required, which itself will cost millions of dollars. Such a design does not seem possible in the current state-based planning regime. A fully fledged national planner could undertake it. It may—although it need not—take some years to build support across the two levels of Government and to implement the Update’s recommendations on the integration of transmission planning for a national electricity market. In the meantime, the detailed design warrants early Commonwealth financial support, analogously with and complementary to support for the “Connecting renewables” fund.

Box 10: Integrating intermittent generation sources

Wind and solar generation are seen as having problems as a result of their intermittent output and the need to invest in expensive storage. While there are definite limits to the use of intermittent renewable energy in the absence of balancing capacity from pump hydro, other storage or gas generation, the real-life experience of South Australia in integrating wind helps to define some limits to the problem.

With 1,170 megawatts of large-scale wind generation installed, and more under construction (AEMO 2011), South Australia has perhaps the world's highest relative wind penetration of any major power system with weak interconnection with other power systems (see Figure 11).[14] In still conditions, the entire wind output can drop to zero. In windy conditions, output approaches capacity. Meanwhile, South Australian demand can be as low as 1000 megawatts on windy nights and as high as 3,300 megawatts on a still, hot day. AEMO only counts 3 per cent of wind's capacity as reliable at peak demand times (AEMO 2010d).

Figure 11: Wind energy penetration



Source IEA 2009 and AEMO 2011.

Nevertheless South Australia has managed well, both in terms of attracting enough reliable generation to supply the other 97 per cent of demand, and in coping with wind's variations and occasional surpluses. South Australia has sufficient non-intermittent capacity to meet its demand and reserve requirements at present, and more gas-fired peaking projects are under development (AEMO 2011). It has never had a serious security event caused by a wind speed change nor is any anticipated in the near future (AEMO 2010b). This is despite South Australia having no hydro-electric capacity to provide low-cost balancing capacity – it relies entirely upon fossil fuel generation to "back up" the wind. Other power systems seem to have had more difficulties, despite lower wind penetrations (ERCOT 2008). This suggests that the Australian National Electricity Market may have some special strengths.

The dispatch process sets a spot price for South Australia every 5 minutes from current supply and demand. Prices hover around $50 per Megawatt hour over considerable periods. However, when demand rises strongly or supply falls back, prices go up to the regulated maximum of $12,500 as the

[14] Note Denmark has a higher proportion of wind installed, but it is more strongly interconnected to neighbouring power systems than is SA.

market seeks to bring supply into balance with demand. When demand falls below expectations or increases in supply surprise the market, price can go into negative territory, right down to minus $1,000. Every generator is exposed to these varying prices for its full output, which creates strong incentives to respond. Wind generators do, occasionally, “spill” some of their energy to avoid paying negative prices thereby resolving the surplus (Swift & Bowker 2010). And with prices being reset so frequently, the market quickly adjusts when the wind speed changes. (AEMC 2009a).

The dispatch process is assisted by a wind energy forecasting system developed by the Australian Energy Market Operator with government assistance (AEMO 2009b). This helps non-intermittent generators to prepare their own operations and effectively “back up” the wind.

Because the South Australia price tends to be low when it is windy and they are generating most power, wind generators earn average spot price revenue substantially below that of other generators: In 2008/9 the average South Australian wind generator received $49 per MWh as opposed to $74 for others (Swift & Bowker 2010). This is an appropriate signal given the transmission constraints, encouraging wind developers to spread more evenly across the National Electricity Market.

As is seen in Figure 11, national wind penetration is low. As much as 8,000 Megawatts of wind and solar generation is expected across Australia by 2020 (AEMO 2010e), but this will be a lower penetration than South Australia has now. Presuming the sources are evenly spread, or the national character of transmission is enhanced, there seems no reason why the National Electricity Market will have difficulties accepting it or require expensive storage technologies. This is not surprising, as 8000 Megawatts is smaller than the amount of day to day demand variation experienced presently.

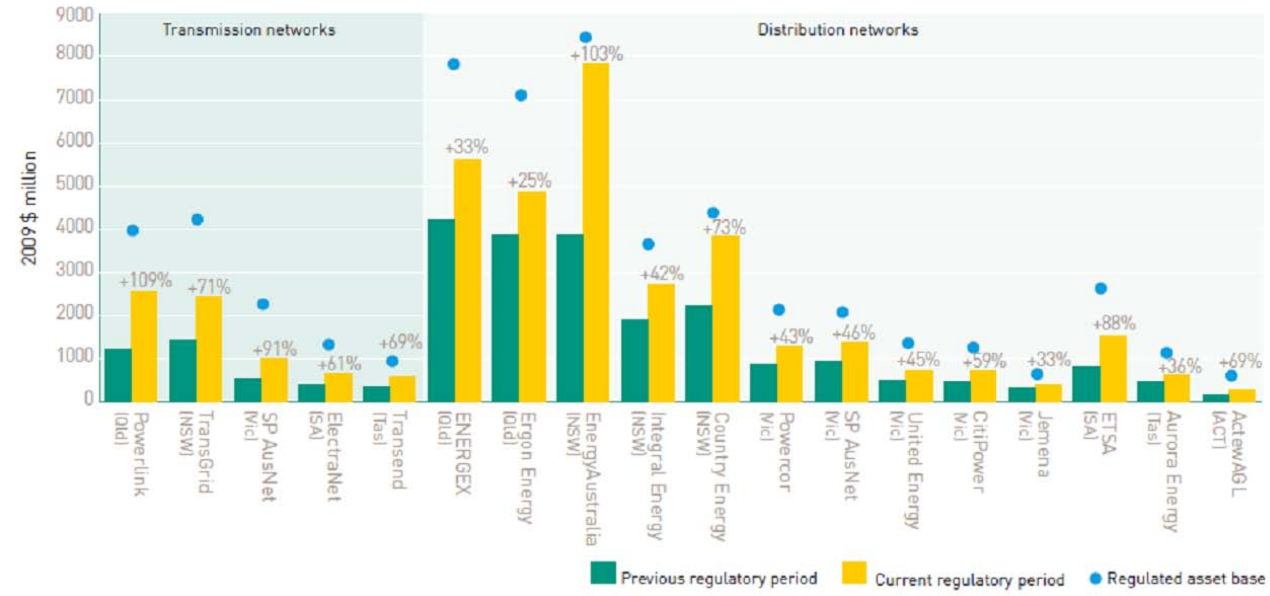
At the same time, the absence of deeper interconnectivity allowing easy dispatch of cheap wind power from high quality South Australian resources to other states, causes a loss of specialisation according to comparative advantage within the National Electricity Market. One Victorian generator noted that there were advantages in weak interconnectivity, “to prevent the transmission of South Australia’s low and variable prices to Victoria”. This, of course, is simply another manifestation of the universal appeal of protection from the perspective of some established interests, and of free trade from the perspective of the national interest.

5. Network regulation

Section 2 showed that Australian electricity prices have risen dramatically since current regulatory arrangements were put in place around 2006; and that there has been no comparable movement in major advanced economies. It showed that the main cause of the massive uplift has been the high capital cost of investment in electricity distribution networks. Transmission network investment over the current five year regulatory periods is forecast at over $7 billion and $32 billion for distribution networks (AER 2010a). This represents a rise in investment from the previous periods of 84 per cent and 54 per cent (in real terms) in transmission and distribution networks respectively (AER 2010a). The increases in network investment and prices have been greater in some states (Queensland and New South Wales) than others (Victoria).

There may be good reasons for some of the acceleration of network cost increases. A catch-up on past underinvestment, especially in the early years of corporatisation, is said to be one of them. There are, however, questions to be answered. Is the current regulatory framework generating excessive investment in distribution and intra-state transmission? Is there excessive investment in infrastructure (“gold plating”) under the guise of reliability? Is investment being rewarded for relatively low risk investment at rates appropriate for more common riskiness of business investment, thus contributing to increases in prices? Is there an asymmetry in incentives for different kinds of investment, discouraging investment in economically managing demand growth, and encouraging expansion in energy use and is there a need for an increase in investment in distribution and extra state transmission above earlier periods has decelerated?

Figure 12: Electricity network investment



Note: Regulated asset bases are as at the beginning of the current regulatory periods. Investment data reflect forecast capital expenditure for the current regulatory period (typically, five years). See AER 2010a for the timing of current regulatory periods.

Source: AER (2010a).

The focus of this paper is on the transformation of the electricity sector with the introduction of a carbon price. That transformation will necessarily be associated with some increases in household and industrial electricity prices. The transformation is rendered more difficult politically by the extraordinary growth in Australian electricity prices that began about five years ago and is expected to continue. This adds to the reasons for analysing the price increases carefully, and avoiding them to the extent that they are shown to have no economically sound basis. Here we can do no more than develop a prima facie case for a close examination of the regulatory framework of electricity pricing, with a view to others examining and correcting weaknesses as soon as possible. We make the case for these issues to be examined closely in upcoming reviews of the regulatory arrangements, including the current review of the regulatory rules by the Australian Energy Regulator.

This section presents a brief overview of the regulation of networks in Australia and an assessment of current arrangements. It follows this with discussion of a related matter: the role of the network in small scale distributed low-emissions generation technologies.

5.1 The regulation of network providers in Australia

While the Australian wholesale and retail electricity markets are competitive, the connections between producers and consumers—the transmission and distribution infrastructure—are natural monopolies. In the absence of price regulation, firms which control the network can be expected to exploit their monopoly position. So price control is an integral part of the regulatory framework. Price control in the natural monopoly of network infrastructure raises quite different issues to price control in competitive retail and generation markets.

The regulatory framework governing transmitters and distributors in Australia is the product of a long reform process. It is also a work in progress. The goal of network regulation is to restrict the ability of network providers to extract monopoly rents, while maintaining appropriate incentives for meeting demand for services, efficiency, reliability and innovation. The ideal is for the regulated network provider to behave as if it were a player in a competitive industry. This is easier said than done.

Box 11: Rate-of-return versus price-cap regulation

The traditional approach in many countries to regulating monopoly networks has been to control the rate of return on approved investment. The regulator determines an appropriate level of providers' operational and capital expenditure, and a rate of return on assets that is meant to relate appropriately to market returns. The process is heavily reliant on the discretion and judgement of the regulator. The problems associated with this regulatory approach are well known (Averch and Johnson 1962). If the regulated return is above the investor's required return, there will be incentives to wasteful over-investment. An unnecessarily high rate of profit will be allowed on an unnecessarily high level of investment in the setting of prices. Set the rate too low, and there will be underinvestment, and valuable services may not be provided. So a great deal hangs on setting the correct rate of return. And yet it is especially difficult to set the right rate of return since the investor knows much more about the inherent riskiness of the investment (which affects the supply price of investment) and, obviously and decisively, about its own supply price of investment. Outcomes are likely to be superior to what would occur in the absence of regulation, but there is much scope for the outcome to go horribly wrong.

Recognition of these problems led to the development of "incentives-based" regulation in the United Kingdom in the 1980s (Joskow 2006). In its purest form, the 'price-cap' approach involves the regulator setting an efficient price for the service, which is reduced in real terms over time in line with the expected efficiency gains available to the firm. Incentive-based regulation is commonly known as 'CPI-X' regulation, because it typically allows prices to rise at the rate of general consumer prices less a constant, 'X', which is the efficiency benchmark. If the firm outperforms this efficiency benchmark, its shareholders capture the savings, providing an incentive for efficiency. There is no incentive for over investment, so the central problem inherent in rate-of-return regulation is avoided. The efficiency benchmark, 'X', is ideally based on the potential performance of the industry as a whole (in terms of, for instance, Total Factor Productivity), or on that of firms similar to the regulated provider. Problems with a pure price-cap approach include difficulties with practical implementation and misjudgement or misinformation on firm-specific factors.

The regulatory regime adopted by the Australian Energy Regulator seeks to draw from both approaches. There have been proposals to move more in the direction of the price-cap approach, with a particular focus on Total Factor Productivity benchmarking (AEMC 2011). Concerns have been raised about this by the Australian Energy Regulator, amongst others, and limited progress has been made to date. There have been instances in the United Kingdom where the 'pure' price-cap approach has been diluted to move towards the rate-of-return approach, with the regulator determining an appropriate rate of return on capital and requiring a specified improvement in efficiency.

The regulatory framework affects prices through two mechanisms: the rate of return allowed to the investor; and the level of investment by the network on which a return is allowed. The ideal is to allow a rate of return that contains no monopoly rent (that is, that equates to the supply price of investment), and which induces the optimal level of investment. These are the primary goals of network regulation and there are a number of methods for doing so (see Box 10).

The Australian Energy Regulator is responsible for the regulation of all transmission and distribution network service providers in the National Electricity Market. The approach of the regulator is stipulated by the National Electricity Rules (AEMC 2011). This approach combines aspects of the 'rate-of-return' and 'price-cap' methods. While the former avoids under compensation but may encourage overinvestment, the latter provides the appropriate incentives but can be difficult to implement. The combined approach—which the regulator calls the 'building blocks method'—is intended to strike an appropriate balance between the two.

The building blocks approach considers the following aspects of a provider's business: existing assets; forecasted capital expenditure to supplement existing assets; forecasted operating expenditure to maintain the asset base; a market-based rate of return on capital; and depreciation and taxation expenses.

The regulator performs a regulatory determination every 5 years. In the lead up to a determination, the provider submits a proposal for the upcoming regulatory period. It claims values and forecasts for the variables listed above and these are considered by the regulator, which typically involves consultation with engineering experts to assess the claims. It is typical for the regulator to reject aspects of a provider's proposal and to invite revisions. An important part of this process is the regulator's determination of an appropriate cost of capital for the firm. The result of this process is the determination of the Maximum Allowable Revenue for the firm throughout the 5-year regulatory period.

Aspects of the regulator's determination are commonly subject to appeal by the provider with the Australian Competition Tribunal. This may result in a revision to the firm's Maximum Allowable Revenue. Once the final revenue path is determined, the firm is able to capture any efficiency gains it can achieve below its allowed revenue path within the regulatory period. However, any under expenditure on capital is 'clawed back' to some extent when the regulator determines its revised asset base in the following regulatory determination. The size of the asset base is important as it will feed back into future revenue claims.

Of course, as with all regulated monopolies, there are substantial difficulties. Information asymmetries between providers and the regulator may allow firms to make excess profits and to have large incentives for wasteful over-investment. It is also extremely difficult to get the balance of incentives right.

Firms have an incentive to overstate the size of their asset base and their capital and operating expenditure, since they capture any cost savings that they can achieve within the regulatory period. The regulator's ability to prevent this is always limited. Not only is there an incentive to overstate the size of the asset base, but there may also be an incentive to over-invest in the asset base. If the cost of capital determined by the regulator is too high, then the firm will have a stronger incentive to build up the asset base than to find savings in the 5 year period. In essence, the firm can profit from over-investment.

If the cost of capital is set too low, on the other hand, then the firm could under-invest in the asset base, which could threaten the performance or reliability of the network. It is quite clear that in Australia the rate of return has not been set too low.

The regulator's cost of capital determinations—an important part of the revenue stream—are almost always subject to appeal by providers and there are several instances where the cost of capital allowance has been revised upwards. There seems to be little recognition that investment in the network is recouped with near certainty, being passed on to creditworthy retailers who recoup it from customers. It is the kind of investment that, effectively packaged, would be attractive to superannuation funds and other investors seeking to place a proportion of their assets into low-risk activities earning low returns. And yet the discussion of returns proceeds as if this were a mixture of ordinary business equity and debt investment, earning normal commercial returns for debt and equity.

Regulatory imperfections in this area can lead to excessive returns being allowed on investment and in turn encourage over investment. The extraordinary increases in the regulated components of electricity prices since this system has been in operation confirms the case for the system to be subject to an early and searching independent review.

5.2 A brief assessment of the Australian regulatory regime

I have identified several areas in which the current regulatory arrangements may be functioning poorly, leading to unnecessarily large increases in electricity prices which the broad regulatory framework is sound, aspects of the rules constrain the ability of the Australian Energy Regulator to perform it's role effectively, and create incentives for network businesses to behave in ways that are contrary to the interests of electricity consumers. These areas are examined briefly in this paper simply to make the case for urgent and thorough review.

The potential for providers to profit from over investment

In the regulator's determination process, the weighted average cost of capital is determined by a rules-based formula, which accounts for the cost of equity and debt, and provides for income tax. Ideally, the rate would be set at a level that reflects the appropriate risk exposure of the provider.

In practice, the rules do not appear to achieve this. In the United Kingdom, the cost of debt is derived from the price of bonds actually sold by low-risk network businesses. In Australia the cost of general corporate debt is used, which has an interest rate around 2.5 percentage points higher (Mountain & Littlechild 2010). If regulated firms can borrow more cheaply than the rate of debt allowed through the regulatory process, then they can profit from over investment.

The rate of return allowed on the equity component of the weighted average cost of capital does not seem to reflect the low risk of these investments.

Where the business is government owned, the regulated rate of return exceeds the true underlying cost of finance to the owner to an even greater extent. For instance, in February 2011, the average interest rate on 3-year New South Wales Government bonds was around 5.5 per cent, compared to the average interest rate on AA-rated 1-5 year corporate debt of around 6.1 per cent.

Further, where the State Government is the owner, it retains the tax allowance for which provision is made in the weighted average cost of capital. Unlike taxation, royalties and many other sources of revenue, the profits of state-owned businesses are exempted from the equalisation rules under which the Commonwealth Grants Commission allocates GST revenues amongst the states. So there are cascading mechanisms through which the shareholders of state-owned businesses—like most electricity distribution businesses outside Victoria—do well out of over-investment. May be, that provides part of the explanation for why government-owned network providers invest more heavily than privately owned providers and have consistently over-spent their regulated allowance (Mountain & Littlechild 2010). May be that is why the rate of increase in distribution and intra-state transmissions investments is so much higher in other states (with mainly state-owned distribution enterprises) than in Victoria (where these assets are owned privately).

While the focus of this discussion has been on public network providers, this does not imply that there are no problems with misplaced incentives for investment by private investors as well.

Overly generous appeals processes?

The regulatory regime in Australia includes a merits appeals mechanism, in which a firm can confirm proceedings to the matters on which it is likely to gain as grounds for appeal. The appeal cost itself is an allowable operating expenditure to the firm, which justifies an increase in electricity prices. Appealing a decision is free to the firm and without a realistic possibility of an adverse outcome. Unsurprisingly, appeals automatically follow all regulatory determinations. This must in turn burden the regulator's decisions, which knows that wherever it applies judgement it must favour the firm or be overruled at appeal.

For example, in a recent setting of the weighted average cost of capital, the Australian Energy Regulator had recommended a rate of 6.35 per cent, but this was increased on appeal to 7.5 per cent (Mountain & Littlechild 2010). The dispute related the regulator's assessment of the cost of debt and whether the rules permitted the regulator to use its preferred approach. The decision found against the regulator, a result worth approximately $2 billion to the relevant transmission and distribution businesses (AER 2009b). The $2 billion cost of raising the weighted average cost of capital was of course met by electricity users. It is surprising that a state owned enterprise which effectively has the opportunity to borrow at the government bond rate, should require an additional 1.15 percentage points to cover the debt component of its cost of capital.

It is not obvious why an appeals process is appropriate in these circumstances. If it were appropriate, most informed minds would turn to a more balanced approach. One such approach is that employed in the United Kingdom, where the appellant must query the determination as a whole, and thereby accept the risk of an unfavourable outcome. Appeals are rare in the United Kingdom.

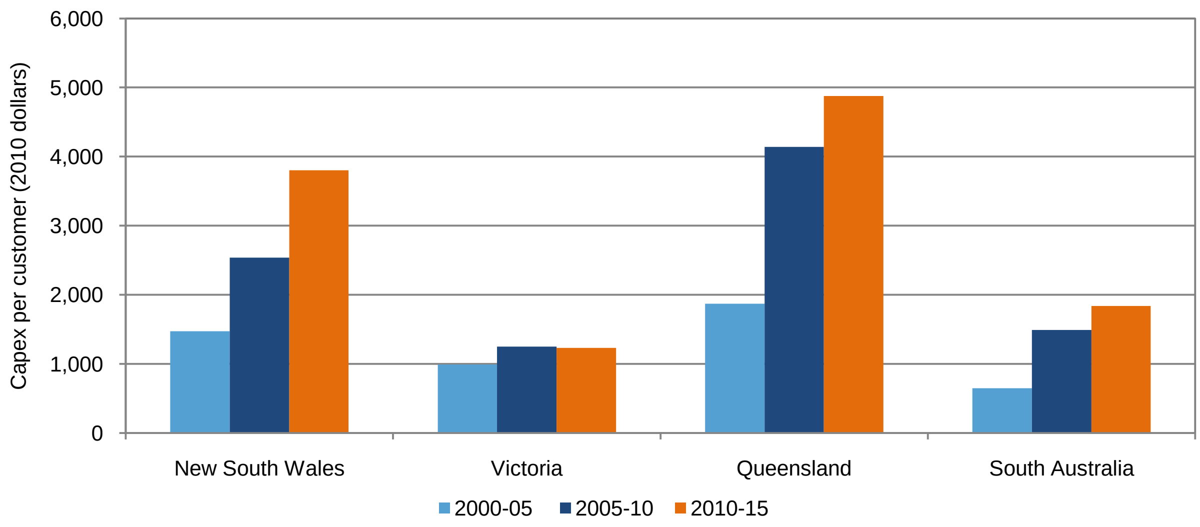
Gold plating of infrastructure, excessive reliability concerns and state ownership

For state owned network service providers, there is an unfortunate confluence of incentives that may be leading to significant over investment and gold plating of network infrastructure. As discussed earlier, state government owners may have an incentive to over invest because of the low cost of borrowing and tax allowance arrangements. In addition, political concerns about reliability of the network, about the ramifications of any failures, may further reinforce these incentives.

The existing financial incentives for state owned network providers to over invest coupled with the political cost of any failure in the network managed by a state owned company, have the potential to overwhelm any countervailing incentives to minimise operational costs.

The comparison of costs between Victoria, where the network providers are in private hands, and New South Wales and Queensland, where the network providers are in state hands, is at the very least a compelling piece of evidence to support this contention. While there are likely to be genuine differences between the states that explain some of these divergences, it is unlikely that these differences explain the majority of these divergences.

Figure 13: Real capital expenditure per customer



Source: EUAA 2010.

5.3 Steps towards a better regulatory regime

The Australian Energy Regulator will complete its first cycle of regulatory determinations for transmission and distribution network services providers in 2011, at which point it will take stock of the regulatory rules under which the determinations were made (AER 2011). It is also considering ways to enhance incentives for network efficiency. This is an opportune time for the questions raised in this paper to be carefully considered by the relevant regulatory bodies.

Strengthening and improving the regulatory rules may yield large benefits in lower rates of increase in electricity prices. The rules should relate the cost of equity and debt capital to the riskiness of the investments. Upgrading of reliability and other standards should be subject to close analysis and, desirably to consumer choice. The appeals mechanism should impose upon the appellant two-sided risks, and provision should be made for persuasive advocacy of the public interest in low electricity prices. Regulated firms should be required to appeal the judgement as a whole, and not be able to appeal on select issues. If government ownership continues, then the rules should allow the regulator to take a different approach in regulating government-owned firms. Regulatory determinations involving government owned firms should account for their unique borrowing and taxation arrangements.

As these changes are intended to reduce overinvestment in the network, some reductions in reliability are possible over time. The regulatory framework includes service standard incentive mechanisms, and providers score well against them at present. It will, however, be necessary to ensure that these schemes are appropriate to good performance in an environment in which companies are trying to reduce, rather than to increase, expenditure on the network.

5.4 The role of distributed small scale generation technologies in networks

The traditional generation sector tends to comprise large, centralised power stations located some distance from load, with energy transmitted through transmission then distribution networks. The industry has developed in this form for good reason: it enables exploitation of remote fuel resources, and, just as significantly, economies of scale. As a result, the traditional generation format is likely to continue in a low-emissions future.

However, with improvements in small-scale generation technology, and the transformation accompanying a carbon price, the contribution of small generators downstream of transmission lines—closer to households and businesses—will become more important. Renewables, like solar, wind, biomass and gas-fired distributed generation technologies (primarily gas-fired generators), co- and tri-generation, will become more cost effective and competitive. In some cases, they will offer major benefits in terms of avoided emissions, network losses and infrastructure expenditure.

Realising the benefits

Co-generating electricity uses thermal energy which would otherwise go to waste. Gas-fired co-generation, for example, has large thermodynamic advantages over burning gas for heat alone. Electricity prices that embody the cost of carbon will allow the environmental benefit of this to be internalised. However, producing downstream electricity through distributed generation has other advantages which are hard for the distributed generator proponent to capture, such as the avoidance of network expenditure if the output of the distributed generator is correlated with the demand peak.

Australian buy-back electricity tariffs are enormously complex and diverse. They are influenced by a combination of the metering technology employed, ad-hoc government incentives, consumer protection laws and the preferences of the network and retail companies. They should be replaced by an efficient price based on the characteristics of the specific load or generator. Interval metering of output, combined with payment that varies over time, could reflect the different value of different generators without the use of separate tariffs and metering configurations for each.

National Electricity Market rules allow the profile to be economically priced. In practice, cost-reflective pricing is limited by the cost of changing metering technology, and other transaction costs involved with setting cost-reflective prices (including network prices). Metering technology is progressing, as discussed below, and so the network company incentives are the area deserving most public policy attention.

The expansion of distributed generation

From 2005 the Australian Energy Regulator began providing distribution companies with specific Demand Management Innovation Allowances. These allowances are to be used to investigate, or invest in, non-network approaches—distributed generation and demand-side response—to manage peak or general demand. Distribution businesses can recover the implementation costs, up to the value of the avoided distribution costs plus, in some jurisdictions, foregone revenue costs of demand management programs. The quantities of funding are in the order of $5 to $10 million per annum over the period 2009 to 2014/15 (AER 2008a, AER 2010a, AER 2010b).

The Australian Energy Market Commission’s stage 2 Review of Demand Side Participation in the National Electricity Market concluded that these incentives are worthwhile, and recommended a number of inclusions—including its extension to innovation in the connection of embedded generators to distribution networks (AEMC 2009b).

Currently, demand management as part of the scheme is not subject to auditing requirements (AER 2008b). However, as greater activity is undertaken under the fund, a review of the effectiveness of this fund is recommended. Greater commercialisation of existing demand-side technologies and practices can only come about when they are considered as a normal part of network company business.

As discussed in this section, there are numerous signs of excessive investment in regulated network infrastructure assets. Correcting any over-investment will offer not only lower, and more efficient, prices for consumers, but will also reduce the current conflict between the desire to over-invest in one’s own assets, and connecting and contracting with distributed generation. When the network company can profit from investing less rather than more, then it will seek ways to foster distributed generation and to set economically efficient tariffs.

In relation to facilitating distributed generation, the 2008 Review stated: “The first best solution would be reform of the regulatory framework for distribution businesses (but that) the first best solution may not be achievable in the short-term.” Given the rapid rise in network costs in the last three years, it seems that this first best solution should be implemented with urgency. This will also greatly assist distributed generation.

‘Smart’ energy technologies

The emergence of new ‘smart’ energy technologies, including smart meters and smart grids, combined with an increased focus on energy efficiency, has the potential to alter consumption patterns and mitigate the growth in capacity requirements.

There are significant benefits associated with smart meters—particularly when combined with communication technologies and appropriate electricity tariffs. They can offer consumers the ability to manage their demand and expenditure (particularly during peak times), and they can make it possible to charge prices for electricity that reflect its true cost at different times (time-of-use pricing) and invite further consumer response to this price signal. Smart meters are a platform for innovation.

Australian governments are implementing plans to introduce smart meters with communication capabilities: the roll-out of meters has commenced in Victoria. Evaluations of Victoria’s roll out of advanced interval meters have confirmed its cost effectiveness. Over the period 2008-2028, it is estimated that the Victorian program will cost around $1.6 billion, and will deliver benefits worth between $2.6 and $5.0 billion (Oakley Greenwood 2010). Direct costs for consumers were around $70 per household over the year 2010, and expected to be around $78 in 2011, though they will decline over time (AER 2010a).

Smart grids combine smart meters, communications and metering infrastructure with other technologies in the electricity network. They can improve the reliability of electricity services for consumers by identifying and resolving faults on the grid, better managing voltage, and identifying infrastructure that need maintenance. Smart grids can allow better integration of distributed generation, and storage. They also allow electricity providers to help consumers manage their electricity consumption and enable the use of smart appliances and smart charging (for example, of electric vehicles) that can be programmed to run on off-peak power. Financial savings are significant (see Box 12 below for an Australian estimates) and benefits are also large in terms of energy savings and emissions reductions. A recent US study estimated full penetration of smart grids would deliver direct reductions in electricity sector energy and CO_2 emissions of 12 per cent in 2030, with a further 5 per cent indirect reduction achieved through supporting penetration of renewable generation (Pacific Northwest National Laboratory 2010).

Investment in trials and deployment of smart grid technologies requires innovation of a kind that suffers from market failures, including spillovers and collective action problems. Government funding of innovation therefore has a role. Smart grids were a major focus of the United States' Recovery Act funding, with around $3.4 billion provided through a competitive grant process—the Smart Grid Investment Grant Awards—for almost 100 projects nation-wide (US Department of Energy 2010). Organisations like the GridWise Alliance in the United States will also be important to overcome information asymmetries and bring disparate interest groups together to promote Smart Grids. An Australian example is described in Box 12 below.

Box 12: Smart Grid, Smart City

The Australian Government's Smart Grid, Smart City program will fund trials on smart grid technologies, to demonstrate a fully-integrated, commercial-scale smart grid deployment in Newcastle and surrounding locations. It builds on programs for many smart grid elements, including smart meters, dynamic pricing and distributed generation, that have already been the subject of trials in Victoria and the Solar Cities program.

Participants in the program will have in-home displays to monitor energy usage, and can then manage and program intelligent appliances to run on off-peak power. Fault detection, isolation, and restoration will sense faults on the grid and allow re-routing of supply. The grid will also integrate distributed, renewable energy, and undertake trials on distributed storage (DRET 2011).

The Australian Government funds ($100 million) are intended to offset some of the technology risks of the project (Australian Government 2009a). The business case for the project estimates that gross benefits could reach at least $5 billion annually, with gains largely from power information and management technologies for customer applications ($1.3 billion), voltage control and reductions ($700 million), fault detection, isolation and restoration ($900 million) and distributed storage ($500 million) (Australian Government 2009b).

The project will yield important data, including optimising societal benefits by prioritising applications, and potential synergies with other infrastructure and technology investments.

6. Households and electricity prices

The rapid lift in household electricity prices over the past four years has hit all households but it tends to disproportionately affect low income households who spend a higher proportion of their income on electricity.

While the impact of the carbon price on electricity prices will be smaller than recent and prospective increases that have nothing to do with carbon pricing, it will still be important to understand how the increase in prices driven by the carbon price will affect households and especially low income households.

While this section does not consider policies to assist low income households response to higher electricity prices in general it does consider policies to assist households for carbon related price increases. Of course, a great benefit of the market based carbon pricing arrangements is that they generate revenue with which households can be supported without affecting the incentive to lower the consumption of emission intensive goods and services.

Patterns of household electricity consumption

Low-income households tend to consume less energy and fuel than high income households but to expend a significantly higher proportion of their income on these items. The Australian Bureau of Statistics (ABS 2006) reports that low income households spend on average, half as much in dollar terms as high income households but that this is nearly double the proportion of total expenditure. These relativities have remained consistent over time (ACOSS 2008).

Rural households also tend to spend proportionately more on electricity than urban households. This difference may primarily reflect the differences in average income across rural and urban households, as rural incomes tend to be lower on average. In 2003-04, rural households applied just over 2.3 per cent ($19.95 per week) of their expenditure on electricity, compared to around 1.7 per cent ($16.27 per week) for households in major urban areas. This rigorous assessment by the ABS, through the Household Expenditure Survey, is outdated, with the most recent data available being from 2003-04. The next iteration of the HES is yet to be released by the ABS, meaning updated comparisons cannot be made with the 2003-04 survey. In recent years, changed prices of electricity (and other goods) will have affected expenditure, and potentially demand. While not as comprehensive as the Household Expenditure Survey, there are more recent data sets available to shed light on these changes.

One of these data sets is the Household, Income and Labour Dynamics in Australia (HILDA) Survey, managed by the Melbourne Institute at the University of Melbourne. It shows much the same results as earlier studies. The HILDA data (collected regularly between 2005 and 2009) shows that household energy[15] expenditure increases with household income (and the proportion of income spent on energy is higher for low income households) (HILDA 2010). These patterns are confirmed in regional studies, like that undertaken by the Independent Pricing and Regulatory Tribunal of New South Wales (2010). HILDA (2010) data show some evidence of household energy expenditure increasing with time, especially between 2007 and 2009, which would reflect the recent electricity price rises. Weekly energy expenditure among the lowest income quintile increased by $3.30 between 2007 and 2009, from $18.30 to $21.65.

Further evidence has emerged that recent electricity price rises are placing added financial strain on households, particularly low income households, and this trend is forecast to continue (see figure 14 and for a further discussion Sims 2010). The New South Wales Energy and Water Ombudsman reported that 4,103 customers had problems paying their bills, a 41per cent increase from the previous year (Energy and Water Ombudsman NSW 2010). IPART's 2010 survey of households in the Sydney

[15] HILDA's definition of 'energy' includes electricity, gas and other heating fuel.

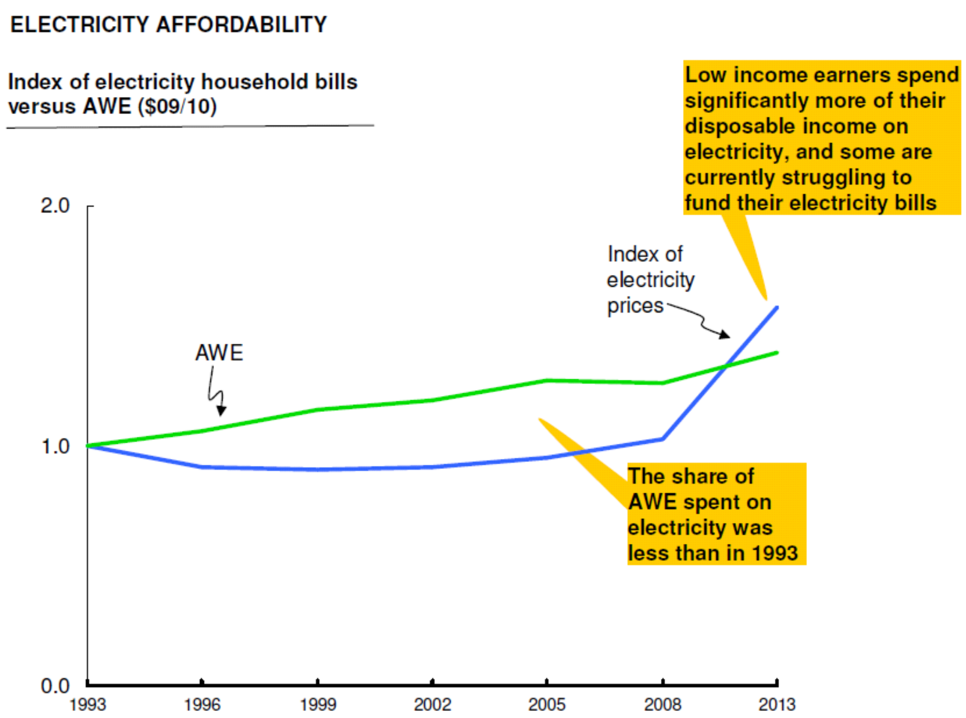
region confirmed this trend. Similarly, in 2009-10, the Victorian Energy and Water Ombudsman pointed to increasing customer financial hardship, with cases related to energy disconnection up 54 per cent, and negotiated payment plans up 31 per cent from 2008-09 (Energy and Water Ombudsman Victoria 2010).

There have been some moves by state governments to increase the level of assistance to vulnerable energy consumers through Community Service Obligations, such as rebates and concessions. For instance, the New South Wales Government increased its energy rebate (and expanded the rebate's eligibility) from 1 July 2010 and a further increase is due from 1 July 2011.[16]

6.1 Assisting households

In 2008 analysis by the Australian Treasury, it was predicted that in the first five years of carbon pricing, average household electricity prices would initially increase by around 20 per cent under the CPRS-5 scenario, where carbon prices start at $23 (2005 dollars). That proportion would have been reduced by the exceptional inflation in electricity prices since then. It will be important to update these assessments to reflect the recent significant increases in base electricity prices.

Figure 14: Electricity Affordability



Source: Sims 2010.

The form of household assistance

Households will feel the effects of the carbon price differently because of variations in their consumption bundle. This argues against prescriptive or directive assistance measures. Therefore, the bulk of the payments should be made through changes to the taxation and social security systems, with the adjustment package to remain in place and adjust over time with a carbon price.

Update Paper six recommended that integrated income tax and social security reform should be the central pillar of household assistance. Maintaining economic growth and full employment within a

[16] The increases are intended to reflect the average rise in the state's regulated electricity prices.

flexible economy, supported by the sound Australian social security system, will be the main guarantor of equity during the structural change triggered by pricing carbon.

Existing taxes reduce incentives for people to enter the workforce and, in the absence of any assistance; a carbon price may exacerbate this effect. Thus, following the introduction of a carbon price, the benefits of addressing existing distortionary taxes will be even greater. Reductions of the effective marginal tax rate for low income households would provide those paying tax with a larger share of their gross income in take home pay. This approach is preferable to returning revenue from a carbon price as a dividend to all households (considered, for example, by Denniss & Richardson 2010, capanddividend.org 2011). Returning money to households as a lump sum would mean that the total effect of carbon pricing and compensation would be to reduce work incentives further.

Box 13: Residential price elasticity

There is some variation in estimates of price elasticity of demand for electricity (see, for example, Economics for Equity and the Environment undated, IPART 2003, NIEIR 2002, OECD 2008). Estimated elasticities vary by energy type, study type, region, and consumer characteristics (OCED 2008). However, there is widespread agreement that the residential demand for energy responds less to price in the short-run than in the longer-run. Estimates of short-run residential price elasticity are generally considered to be around -0.3, meaning that a 10 per cent rise in price results in a 3 per cent fall in demand for energy (OECD 2008). In some parts of Australia, this elasticity may be slightly higher; for example, -0.36 to -0.43 (Fan and Hyndman 2010). Price elasticity is much greater in the long run—around double that of the short-run elasticity, at around 0.7 (OECD 2008).

Tax reform will be supported by adjustments that have been applied in recent years to the indexation of social security payments to reflect changes in the cost of living, including bringing forward some of those changes to ensure recipients are not affected by a lag. Such tax reform and transfer adjustments will continue over time, and adjust with a carbon price. The Update's Final Report will place these issues in a long-term budget context.

Support for targeted energy saving measures

The reforms to the tax and transfer system described above are a highly efficient approach for returning revenue to many of those most affected, while sustaining the price signal from a carbon price. However, this general financial support does not overcome market failures that will inhibit some households' ability to respond to the price signal and reduce their electricity consumption.

The 2008 Review noted the significant potential for uptake of energy efficient practices and behaviours. This potential was recently highlighted by the Prime Minister's Task Group on Energy Efficiency (2010). Because of a number of sources of market failures, the uptake of energy-saving practices or services is sub-optimal:

- Information failure: the public good nature of information creates a barrier to its provision. Without sufficient information, consumers cannot make informed decisions about their purchasing choices and behaviours.
- Bounded rationality and capital constraints: even where people have access to sufficient information, they may make decisions that are suboptimal (for example, not paying more for a gas or solar hot water system, which will save more money later).

- Split incentives, or principal-agent problems: the party who makes a decision (for example, the landlord) is not driven by the same considerations as another party who is affected by it (for example, the tenant).

These market failures argue for additional direct support for those most affected, through targeted energy saving measures for some households (McKinsey & Co. 2009, Australian Government 2008).

While all households are likely to experience at least one of these market failures to some extent, low income households are more susceptible. For example, low-income households have relatively less capacity to pay for energy-saving products, like solar hot water or insulation, which can have significant upfront costs. Low-income households have less energy-consuming appliances in general, but also noticeably fewer energy efficient appliances, and less energy efficient homes (ABS 2010a). In low-income households insulation, is less common, refrigerators are less efficient, and there is a greater reliance on energy intensive electric heating (ABS 2010a). Similarly, principal-agent problems will be prevalent among low-income households, because the total number of renters are greater in low-income brackets (ABS 2008a, IPART 2010b).

A number of existing state and Commonwealth government programs address these market failures, and offer major energy and financial savings. To address information failures, for example, energy bill benchmarking, and appliance labels, are highly cost-effective (see, for example, Energy Efficient Strategies 2010). Tailored energy audits, on-site implementation of simple and low-cost energy-saving measures, and ongoing advice have also achieved strong energy and financial outcomes (Anglicare and TasCOSS 2010, Australian Government 2008, Queensland Government 2011a). Regulatory standards for the minimum thermal performance and energy consumption of some fixed appliances—where benefits to the economy as a whole outweigh costs—can offer major savings (Energy Efficient Strategies 2010, Grattan Institute, forthcoming, Australian Government 2008).

The identification of a market failure does not in itself make a case for government intervention to correct it. One needs to be confident that the government intervention will be a cost-effective means of changing behaviour. Recent problems with Commonwealth schemes argue for caution. Any programmes in future should be modest in dimension, and follow paths that have been clearly demonstrated to be successful.

Despite recent difficulties in administration of energy efficient assistance programs, such as the Home Insulation Program (ANAO 2010), the weight of evidence suggests that it is possible for such programs to be safely and effectively delivered (see, for example, the U.S. Weatherization Assistance Program, the UK's Warm Front, and Sustainability Victoria programs). Several state-based schemes, including the Queensland ClimateSmart Home Service and New South Wales' Home Power Savings Program (see Box 14), have been administered effectively, and suggest that involving State Governments in delivering programs would be beneficial. If programs can be linked to the work already done by a range of non-government organisations that would offer additional benefits—not least effectively identifying the target population. The Kildonan Uniting Care program provides one example (Borrell and Lane 2009).

This suggests future energy-efficiency program administration could be led by State Governments, in collaboration with community non-governmental organisations and energy retailers. Some modest co-funding could be provided from revenue from a carbon price.

Box 14: Examples of state-based household energy-efficiency programs

Queensland's ClimateSmart Home Service (CSHS) began in January 2009 and in February 2011, over 245,000 households had been serviced—that is, an average of 2,200 customers a week. Around 12 per cent of activity was undertaken in rental homes (Queensland Government 2011b).

The program was developed by the Office of Climate Change, with Local Government Infrastructure Services Pty Ltd, a Government Owned Corporation, delivering it, with the support of sub-contractors. Local Government Infrastructure Services Pty Ltd is responsible for quality assurance, customer demand management and performance reporting.

For $50, households receive $450 of service: a qualified electrician provides individualised energy audit and energy saving advice, and installation of a wireless energy monitor, a water efficient showerhead and compact fluorescent light bulbs. Following the visit, customers receive a customised Power and Water Saving Plan, website portal access, both of which reaffirm the tailored advice provided during the program. The program is estimated to save participating households, on average, just over $300 on their annual electricity bills (Queensland Government 2011a, 2011b) .

In New South Wales, the Home Power Savings Program (formerly the Low Income Household Refit program) has provided home energy assessments and retrofits for tens of thousands of low-income households. Eligible low-income households are those that are recognised energy utility hardship customers, or holders of selected concession cards (DECCW 2011).

The Program is managed by the New South Wales Department of Environment, Climate Change and Water, which has contracted Fieldforce Services to perform assessments, retrofits and provide advice (NSW Government 2011). The assessments are provided free to eligible households, along with a package of energy-saving products, including a stand-by saving power board, compact florescent light bulbs, tap flow aerators, low-flow showerheads, draft proof strips and door snakes. It is estimated that these products and recommended energy-saving behaviours will save participating households up to 20 per cent a year on their power use.

7. Conclusion

Australia's unusually emissions-intensive electricity sector is the main reason why Australia's emissions per person are exceptionally large (Garnaut 2008). The transformation of the electricity sector has to be at the centre of Australia's transition to a low-emissions economy for this reason, and also because the lowest cost path to low emissions in the transport, industrial and household sectors involves greater use of low-emissions electricity.

While the challenge posed by the established reliance on coal-based electricity is large, so are Australia's opportunities for the development of alternatives at costs that are absolutely low by international standards. Australia has an abundance of high quality resources of virtually all of the low-emissions alternative sources of energy: gas from conventional sources, coal seams and shale; wind; solar; high grade uranium oxide for nuclear; land with low value for food which is prospective for biomass and bio-fuels; the special opportunities for using algae in saline marine and land environments; wave and tidal energy; and opportunities for geo-sequestration of carbon dioxide.

In an effective global approach to mitigation, Australia would move quickly to begin the replacement of high-emissions coal generation with increased output from currently operating gas plants, would concentrate new investment on gas and renewables, and over time would replace established coal generation capacity with new gas and renewable energy.

Australia is in the process of becoming the world's largest exporter of both gas and high grade uranium oxide for the generation of electricity, as it is already the world's largest exporter of thermal and metallurgical coal. Gas and nuclear power will both be important for the transition to low-emissions energy in Australia's trading partners in Asia. The high energy costs of gas liquefaction and international transport and the negligible international transport costs of uranium relative to the value of power would make gas the main replacement of coal in electricity generation in Australia. While the price of gas is likely to rise considerably in eastern Australia with the development of exports from the east coast, the high costs of liquefaction and transport will keep export parity prices well below the costs in importing countries. Transport economics will cause gas to remain the major source of energy for electricity generation in Australia for longer than in any other developed country. For the same reason, it will take longer for nuclear energy to be an economically efficient source of electricity in Australia than in any other country. Transport economics would exclude nuclear from an early role in Australian electricity supply; nuclear development in the foreseeable future would require the elevation of political preference for nuclear over the economics.

Eventually, with deeper reductions in emissions and a higher carbon price, gas itself would become uneconomic in the absence of low-cost biological or geological sequestration of emissions. Economically efficient sequestration would, of course, give coal a new economic lease on life, and prolong the economic life of gas. It seems likely that sequestration from gas combustion will be cheaper and easier than from coal.

It is not currently clear which energy sources will follow the eventual decline of gas in electricity generation. We do not need to know. It is best to keep a range of options alive. Eventual winners will depend on relative rates of technological improvement, and in the important case of nuclear, by developments in the reality and perception of safety and weapons proliferation.

What is clear is that Australia has many attractive options for energy supply and electricity generation. If the policy settings are right, Australia will be a country of relatively low energy costs and relatively high energy use in the future, as it has been in the past. Good policy settings will provide incentives for reductions of emissions on the demand and supply sides of the electricity market, foster innovation, and minimise costs of transmission and distribution while fostering competition and the emergence of new supply from generation sources which have the lowest possible costs.

Good policy must have at its centre a carbon price, set at an appropriate rate and rising over time at the interest rate until the switch to full emission trading and the linking with other schemes. It must provide fiscal support to match the external benefits that a firm generates when it invests in research, development and commercialisation of new technologies. It should move us in economically appropriate steps to a national energy market (at first covering the five eastern States and the Australian Capital Territory), linked by a truly national electricity grid (with the same geographic reach). Within the National Electricity Market, effective competition will remove the need for price controls at the retail and generation levels. Major parts of the transmission and distribution grids will inevitably have characteristics of natural monopoly; regulation of prices will have an important role, and reform is required to remove current incentives that unnecessarily raise costs.

The considerable progress towards a national (or, rather, eastern Australian) energy market over the past decade or so provides a solid foundation for the reforms that must be made to ensure a smooth and low-cost transition. There is no reason why the transition should be associated with large shocks either to supply or to price. This paper has recommended some additional mechanisms to reduce the small risks to energy security. It has suggested changes to regulatory arrangements for transmission and distribution that could help to moderate electricity price increases as carbon prices are absorbed over the next several years.

Western Australia and the Northern Territory for some time will go their own ways outside the “national” electricity market. Their energy resource endowments are similarly rich to those of the eastern States. Large gas exports mean that gas prices start much higher than in eastern Australia, but the high liquefaction and transport costs for gas will keep local prices well below those in customer countries, and after a while as low as in eastern Australia.

More generally, the policies recommended in this paper and in Update Papers 6 (*Carbon pricing and reducing Australia’s emissions*) and 7 (*Low-emissions technologies and the innovation challenge*) will underpin Australia’s transition from a low-cost high-emissions electricity sector, to a low-cost low-emissions electricity sector. Australia’s is likely to be a large electricity sector compared with other countries, and compared with Australia at present. It will play a major role in the decarbonisation of the Australian economy directly, and through facilitating the decarbonisation of transport, industry and household energy use.

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