11 Electricity transformation

IN 1865, William Stanley Jevons, a founder of modern economics as well as meteorology, published a book called *The coal question*. In it he drew attention to the United Kingdom's limited coal supplies and commented that 'if we lavishly and boldly push forward in the creation and distribution of our riches, it is hard to overestimate the pitch of beneficial influence to which we may attain in the present. But the maintenance of such a position is physically impossible'.

Jevons did some of his seminal work in Australia and his words have a special resonance for contemporary Australians. The largest source of Australia's disproportionately high greenhouse gas emissions is our reliance upon coal in the electricity sector. As such, we face the same choice outlined by Jevons. We might elect to do nothing and continue to enrich ourselves, in part with cheap energy. But in the long run climate change ensures that the maintenance of our current prosperity under business as usual remains impossible.

The transformation of Australia's electricity sector is thus about ending reliance on fossil fuel long before the coal runs out—unless we can capture and safely store the carbon dioxide wastes.

Australia's unusually emissions-intensive electricity sector is the main reason why Australia's emissions per person are exceptionally large. 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 reducing emissions in the transport, industrial and household sectors involves greater use of low-emissions electricity.

A carbon price that passes through to household and business electricity prices will drive the reduction of 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 and 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 people economise on electricity use.

For households, carbon pricing will raise the price of electricity. The price increases associated with the introduction of a carbon price come at a difficult time. There have been large recent electricity price rises that are not related to a carbon price, and without changes in the regulatory arrangements this would continue. The increases are mainly because of large investments in the networks of poles and wires that distribute electricity, and the high rates of return on those investments that are recouped without risk from consumers. These investments have been stimulated by a regulatory regime that provides excessive incentives for investment whether or not it is wanted by consumers. The effects of the resources boom on coal and gas prices and construction costs are likely to increase electricity costs and prices further still.

This circumstance can be corrected. There are strong signs that lower growth in demand is reducing the need for investment. And the inefficiencies in domestic energy markets and regulatory regimes that underpin the rises can be corrected to ease the adjustment to carbon-related price rises. Indeed, These things should be done anyway. The introduction of carbon pricing has drawn attention to their importance.

Price rise drivers

Australian households and businesses enjoyed relatively stable and low retail electricity prices for many decades. After a long period in which Australian electricity prices rose more or less in line with other prices, from 2007 to 2010 prices rose nationally by 32 per cent in real terms. While the consumption of electricity makes up a relatively small component of a typical household's expenditure, rises of this magnitude put pressure on lower-income households.

Electricity prices for businesses have also increased rapidly since 2007. Household and business electricity prices have not always moved together, but recent price rises are common to both.

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. New South Wales and Tasmania have made decisions on electricity prices beyond 2011. In New South Wales, annual electricity prices are expected to rise by around 18 per cent in 2011–12 and by around 10 per cent in 2012–13. Electricity prices in Tasmania are expected to increase by around 10 per cent annually over 2011–12 and 2012–13. These expectations do not contain allowance for a carbon price.

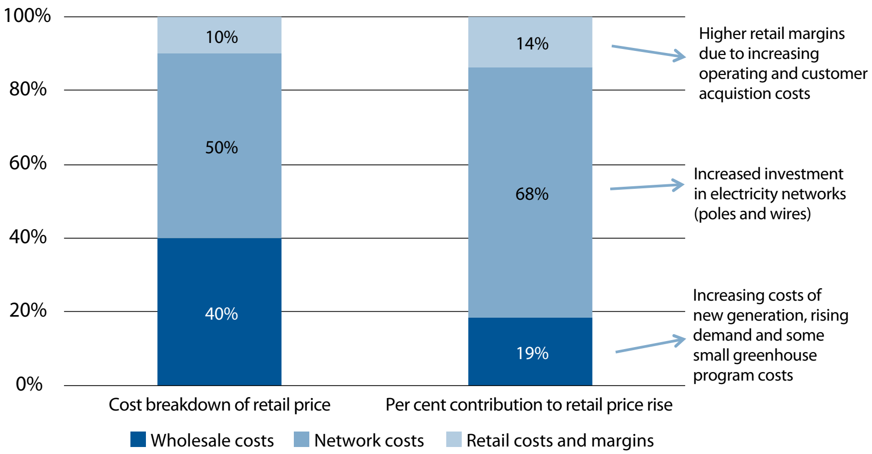
The increases in electricity prices reflect many factors including increased investment in electricity networks—the poles and wires that distribute electricity from power plants to the home—as well as policy changes (such as the Renewable Energy Target) that have led to higher costs.

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 (turbines), the cost of distributing it to households (poles and wires) and the cost of retailing (marketing the product).

The costs of generating power accounted for around 40 per cent of the overall electricity price in 2010 (see Figure 11.1). The cost of moving that power to households—transmission and distribution—made up about 50 per cent of the price. The energy retailers accounted for 10 per cent of the price.

In the current period it is distribution and transmission costs that are the greatest factor in rising electricity prices, accounting for approximately 68 per cent of recent price rises. Retail costs are also increasing much more than the average.

Figure 11.1: Electricity costs and their contribution to current price rises in 2010



Note: 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 in Victoria, which no longer regulates prices).

Sources: Essential Services Commission of South Australia 2010, *Review of retail electricity standing contract price path—final report*; Independent Competition and Regulatory Commission 2010, *Retail prices for non-contestable electricity customers 2010–2012*; Independent Pricing and Regulatory Tribunal of New South Wales 2010, *Review of regulated retail tariffs and charges for electricity 2010–2013*; Office of the Tasmanian Economic Regulator 2010, *Final report—2010 investigation of maximum prices for declared retail services on mainland Tasmania*; Queensland Competition Authority 2010, *Final decision—benchmark retail cost index for electricity: 2010–11*.

In most of Australia, the generator market is competitive and therefore wholesale prices are determined primarily by the dynamics of supply and demand. As consumer prices have risen in the past three years, there has been an easing in the growth in demand. As well, over the past year, milder weather reduced summer demand and industry sources also suggest that the insulation program and photovoltaic installations have had some effect. There have been price fluctuations, in part because of drought as the costs of water-cooled coal-fired power stations rose and because of a reduction in output of the Snowy and Tasmanian hydro-electric systems. The end of the drought placed downward pressure on generator prices from mid-2010.

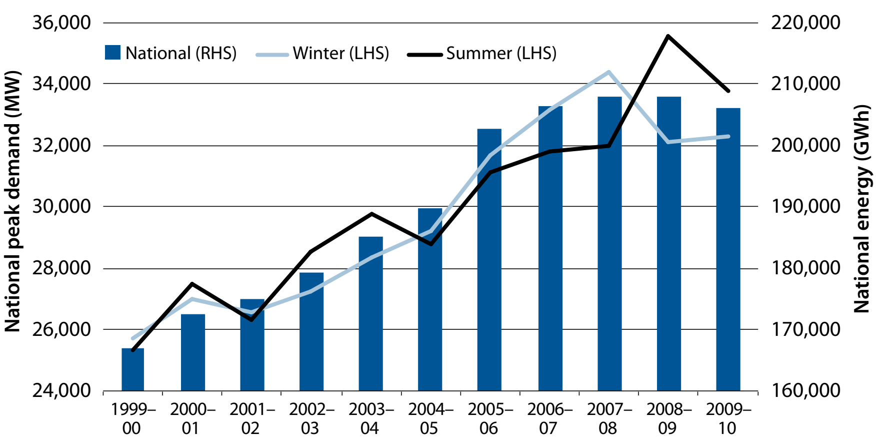
Electricity network costs, on the other hand, have marched higher on the back of a surge in investment. Electricity networks are split into the transmission network and the distribution network. Transmission is the extremely high-voltage assets—metal towers connecting generators to substations. Distribution is the lower-voltage wiring that brings power from substations to customers. Both are regulated under similar rules.

Transmission network investment over the current five-year regulatory period is forecast at over $7 billion and $32 billion for distribution networks. 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.

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

This explanation raises questions. Demand growth has been slow in recent times, long before the cooler summer of 2010–11 (see Figure 11.2). Why does old investment from the 1950s and 1960s suddenly have to be increased now? Certainly there has been growth in peak demand, but this is avoidable: other countries provide high incentives to reduce energy demand at the peaks, while Australian regulatory settings reward distributors for growth in peak demand.

Figure 11.2: National energy demand



Source: Australian Energy Regulator 2010, *State of the Energy Market 2010* and www.aer.gov.au/content/index.phtml/tag/MarketSnapshotLongTermAnalysis.

A second explanation for the rising network costs is that 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. We already have a reliable system. It is important that disciplines are introduced that balance consumers' interest in low prices with marginal improvements in reliability.

This marginal increase in reliability comes at a cost that is paid by all electricity consumers, and not necessarily valued at anything like their cost by many of them. 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.

Price rises have also been stimulated by other government policies. Measures 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—wholesale, network and retail—of electricity costs.

The first of these other government policies is the Renewable Energy Target scheme, in which retailers must ensure that a proportion of their electricity supply comes from renewable energy sources. Renewable energy is currently a more expensive source of electricity and therefore adds to wholesale electricity prices. Unlike economy-wide carbon pricing, the Renewable Energy Target does not necessarily encourage the lowest-cost means of reducing emissions. Nor does it encourage innovation: it favours the lowest-cost established technologies that are eligible within the scheme.

Another policy is feed-in-tariff schemes, which 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.

Benefits of a national network

There is one more source of electricity price rises that must be addressed if we are to maximise the impacts of the carbon price and the fight against climate change. Currently, there are distinct electricity markets in each region of the

National Electricity Market. The interconnectors between them frequently constrain interstate movements, and prices diverge. Investments to supply an interstate market are inhibited.

The cost, risk and facility of transition to a low-emissions economy would be improved if the transmission network of the National Electricity Market became truly national. Benefits would include:

- providing a greater geographic 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, achieving more diversity from intermittent solar and wind resources, 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 are capable of withstanding the early retirement of carbon-intensive generation without physical or financial shocks in regional markets
- providing for more generation competition, bringing customer prices closer to an efficient level, and improving market conditions for smaller, specialist retailers.

There are also a number of detrimental effects from the lack of a truly national grid. These include inefficient overexpenditure on local transmission and distribution justified by supplying the extreme peak with reserve capacity. The National Electricity Market is made even more fragmented by the current rules, which favour intrastate regional flows over those from interstate when there is congestion across boundaries.

It is 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, which are partially privatised. Rather, the newly created National Transmission Planner should assume responsibility for all National Electricity Market transmission planning. This would require each state to separate its transmission ownership from its planning. The Victorian experience shows that the separation is feasible. An empowered National Transmission Planner could develop single national standard charges for transmission, reliability standards and congestion management with much greater efficiency as a dividend.

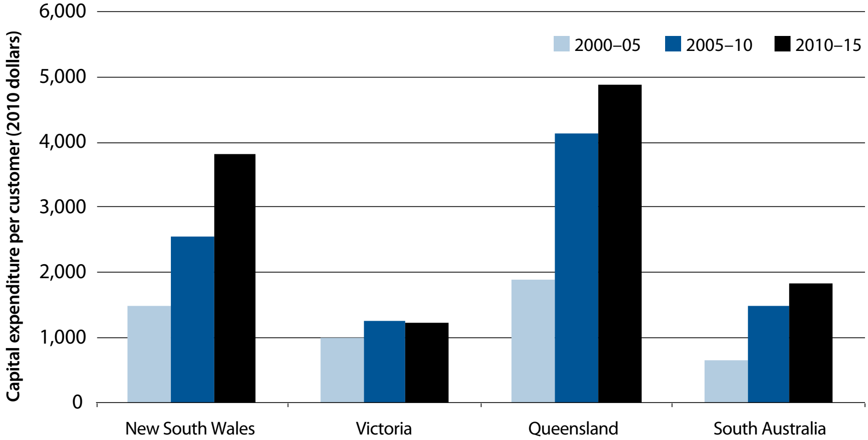
It may appear to be contradictory to suggest the need for increased investment in interstate connectivity to build a truly national market, while drawing attention to excessive investment in distribution networks. There is no contradiction: rigorous assessment of costs and benefits and regulatory systems that avoid excessive rates of return on low-risk investments is required in both cases. Rigorous assessment would lead to much less investment in the near term in one case (distribution), and probably to more and different investment in the other (interstate transmission). Investment in interstate transmission would need to be paid for by some combination of budget subventions and higher prices for consumers. The cost could be minimised by drawing on investors who are comfortable with lower rates of return for low-risk investments of this kind.

Privatising distribution

There is an unfortunate confluence of incentives that has led to significant overinvestment in network infrastructure. It is clear from market behaviour that the rate of return that is allowed on network investments exceeds the cost of supplying capital to this low-risk investment. The problems are larger where the networks continue to be owned by state governments. State government owners have an incentive to overinvest because of their low cost of borrowing and tax allowance arrangements. In addition, political concerns about reliability of the network, and about the ramifications of any failures, reinforce these incentives.

A 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, provides compelling evidence to support this contention (see Figure 11.3). 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 them.

Figure 11.3: Real capital expenditure per customer



Source: Energy Users Association of Australia 2010, *Issues for the MCE: presentation to SCO meeting #59*.

Distribution networks are, of course, natural monopolies. So a strong regulatory regime is required to prevent price gouging. 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. This is a natural time to be considering an overhaul of the regulatory arrangements. Changes will be introduced gradually sometime after that.

But the natural cycle will lead to delays in correction of distortions that are costly to consumers and cause unnecessarily large electricity price rises at a time when the introduction of carbon pricing heightens sensitivity to them. The Ministerial Council on Energy, which is chaired by the Commonwealth minister and which supervises the regulatory arrangements, should bring forward the reform of the price regulation rules. In the states where the distortions are having the largest effects on prices—New South Wales and Queensland—state ownership of the distribution assets affects early implementation of new arrangements.

Where 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.

The regulatory framework includes service standards, 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.

The reform of price regulation must end the current encouragement of increases in peak demand for electricity, and introduce incentives for reducing peak demand.

Enter the carbon price

A carbon price will be the main driver of transformation of the electricity sector. It 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 new investment in low-emissions generation—whether large or small scale. It may lead to fuel switching, so that established generators with high emissions run less intensively and generators that use lower-emissions fuels run more of the time. Or it may lead to the adoption of practices that lead to lower emissions from existing plants and fuels.

There will be some reduction in demand—the overseas studies suggest a 3 per cent fall in demand in the short term after a 10 per cent increase in price, and a 7 per cent increase in the long term. The easing of demand growth as prices have risen in recent years suggests the potency of these effects. Both the electricity price increases from carbon pricing and the larger increases from other sources will pull back demand.

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.

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 feed-in tariffs, should be phased out. The Renewable Energy Target could be phased out by fixing the established price for not meeting the requirements at its current dollar level.

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. First, there is likely to be an initial increase in gas generation. Established gas plants will run for longer hours and coal plants for shorter, at relatively low carbon prices. In expectation of higher carbon prices in future, gas rather than coal will be used in new plants. The highest-cost and most emissions-intensive old plants will close at some time and the capacity that they provided will be supplied from new plants using fuels with lower emissions.

However, there is one proviso. Gas prices in eastern Australia will rise towards the price at which the same gas can be sold to overseas markets as a gas export industry develops there. In this case, the increase in gas generation may be temporarily delayed. The increase in domestic gas prices as a result of the development of an east coast export industry will be smaller to the extent that increasing global gas supplies reduce the international price.

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 low-emissions generators enter the market, supply from more emissions-intensive generators will be gradually displaced and their output gradually reduced.

The introduction of a carbon price will lower the profitability of the most emissions-intensive electricity generators. The most emissions-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 that some brown coal generators are in a precarious financial position even before the introduction of a carbon price, although the profits for Australian subsidiaries reported by foreign owners suggest comfortable margins. Be that as it may, the industry estimates that, over the next five years, $9.4 billion in debt on generation assets will need to be refinanced. Approximately $6–7 billion of this debt is 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. But for generators as a whole, most of the carbon costs are likely to be recouped from price increases. Community concern about higher prices is the mirror image of generator concern that they will not be able to pass through costs: in the final outcome, more passing 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 emissions-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, it is clear that firms will have to manage financial pressures, but the risks to physical energy security are low—if not negligible. The National Electricity Market is self-correcting in terms of physical supplies; 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. This, in turn, provides incentives for additional investment in capacity. 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.

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 assets 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.

Assessing risks

In the debate surrounding transformation of the electricity sector, three types of risks have been commonly cited as threats to energy security.

The first risk is contract market instability. 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 increases in the tendency for the same company to own retailing and generation, 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 a 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 emissions-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 & 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. This should be done through an energy security council with appropriate function. 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.

One possible safeguard against generator insolvency is a government-provided temporary energy security loan guarantee with appropriate limits. Such a device would 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 designed so as to 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 would have the effect of reducing the short- to 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 would reduce the probability of such behaviour interfering with the adjustment to a carbon price.

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

Such an energy security loan guarantee could be available to the small number of the most emissions-intensive incumbents.

The second risk suggested by some electricity stakeholders is that energy security or reliability concerns may arise from weak incentives for firms to invest in maintenance of their generators as they approach the end of their economic lives. There is potential 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 arise with the introduction of a carbon price, although they are unlikely. To the extent that there are grounds for concern, they are more general. The same concerns 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 an owner's financial stress. 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 relating to 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 the end of their lives. However, the incentives to minimise operating expenditure and delay capital expenditure on maintenance will be balanced by market incentives to continue profitable operations. Plants that cut back on maintenance levels will face higher rates of disruption, which will in turn reduce their ability to carry long-term contracts (the 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 preferable in the first instance.

The third risk is the level of future investment in new capacity. 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 in turn will 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.

The role of households

The rapid rise 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 over a number of years that have nothing to do with carbon pricing, it will still be important to understand how any increase in prices driven by the carbon price will affect households, and especially low-income households. One great benefit of 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 emissions-intensive goods and services.

Low-income households tend to consume less energy and fuel than high-income households, but they expend a significantly higher proportion of their income on these items. The Australian Bureau of Statistics reports that low-income households spend on electricity, 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.

Moreover, 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.

Analysis by the Australian Treasury in 2008 predicted that in the first five years of carbon pricing, average household electricity prices would initially increase by around 20 per cent under the scenario aimed at reducing emissions by 5 per cent from 2000 levels by 2020. In this scenario, carbon prices start at about $26, rising by four percentage points per annum plus the general inflation rate. That percentage increase would have been reduced by the exceptional inflation in electricity prices since then.

There is some variation in estimates of the amount by which demand for electricity falls when prices rise. There is some evidence that the amount by which demand falls with a given percentage increase in price may be larger in some parts of Australia than is suggested by the overseas experience to which we have referred. 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. But because of a number of sources of market failures, the uptake of energy-saving practices or services is suboptimal:

- 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).

While all households are likely to experience at least one of these sources of market failure 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 fewer energy-consuming appliances in general, but also noticeably fewer energy-efficient appliances, and less energy-efficient homes. In low-income households insulation is less common, refrigerators are less efficient, and there is a greater reliance on energy-intensive electric heating.

A number of existing state and Commonwealth government programs address these market failures, and offer major energy and financial savings. To address information failures, such measures as energy bill benchmarking and appliance labels are highly cost-effective. 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. 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.

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 programs in future should be modest in dimension, and follow paths that have been clearly demonstrated to be successful. Some of the state government schemes seem to provide opportunities for efficient extension of support for low-income households with special electricity requirements.

Conclusion

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 that is prospective for biomass and biofuels; special opportunities for using algae in saline marine and land environments; wave and tidal energy; location adjacent to the extraordinarily rich hydro-electric potential of the island of New Guinea; geothermal from deep hot rocks; and opportunities for geosequestration of carbon dioxide. Good policy settings, including a carbon price, a fully national electricity market and reformed regulatory regimes will release these potential sources at the lowest possible cost.

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

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 excludes 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 its safety.

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, encourage innovation, and minimise the costs of transmission and distribution while fostering competition and the emergence of new supply from those low-emissions generation sources that have the lowest possible costs.