Investor Group on Climate Change

Potential Earnings Impacts from Climate Change

Energy Infrastructure

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MONASH University

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Note: These reports were researched and written before the Australian Government's commitment to an Australian Emissions Trading Scheme and before any details of the scheme were available. Readers can find more information on policy regarding the Australian Emissions Trading Scheme at http://www.pmc.gov.au/climate_change/#emissions

Executive Summary

- This report explores the exposure of energy infrastructure investments, including electricity generation and electricity and gas transmission and distribution networks, to climate change risk.
- For existing installed electricity generation, carbon price risk is the key immediate threat from climate change. The impact of carbon pricing on existing generators depends on:
  - Design of the emissions trading scheme, in particular, the permit allocation approach adopted. Earnings may reduce by only a small amount or may even increase if a large proportion of permits are allocated for free, which may occur in the early years of trading.
  - Relative emissions intensity. Generators with the lowest emissions intensity per megawatt hour will generally experience the smallest impact on earnings.
- For new generation, carbon price risk may:
  - Delay new investment until there is reasonable certainty about the design and timing of an emissions trading scheme.
  - Change preferences for different forms of generation where carbon prices are sufficiently large. Modelling shows that near term impacts are unlikely to be sufficient for natural gas to become the preferred form of new base load generation based on cost estimates alone.
- For electricity and gas transmission and distribution networks:
  - The 'rate of return' economic regulation that such assets are typically subject to plays an important role in mitigating most climate change risk, by allowing for periodic adjustments of prices to give the asset owner a reasonable return on investment.
  - Climate change has the greatest impact on value where it affects long-term peak demand forecasts and, hence, network growth. This arises because network assets are typically valued at a multiple of the asset base recognised by the regulator (e.g. enterprise value = 1.48 x Regulated Asset Base (RAB)), so changes in network growth have a multiplier impact on value.
  - Climate change is expected to result in a mixture of positive and negative effects on network growth, from both climatic changes and from flow on effects from carbon pricing of electricity generation emissions. The cumulative impact of these exposures, after taking into account the mitigating effect of economic regulation, is estimated to be:

    Electricity transmission: -0.08% change in the RAB multiple with the most significant impact being dampening in the overall growth in electricity demand due to carbon pricing.

    Electricity distribution: +0.23% change in the RAB multiple, with the most significant impact being more frequent and extreme hot weather events, which further stimulates the growth in air conditioning and, hence, peak demand.

    Gas transmission: +0.08% to +0.16% change in the RAB multiple for different networks, with the most significant impact being increasing use of gas for electricity generation.

    Gas distribution: -0.24% to +0.08% change in the RAB multiple for different networks. The most significant impact is in cooler climates where warmer winters are expected to decrease domestic heating demand.

Contents

1. Energy Infrastructure Contribution to Climate Change

The energy sector is a significant contributor to greenhouse gas emissions.

Electricity generation alone produces around 38% of Australia's greenhouse gas emissions and 28% of global emissions.[i] This high proportion of electricity emissions reflects Australia's comparatively high reliance on (relatively inexpensive and abundant) black and brown coal reserves for electricity generation. Without intervening policy measures, fossil fuel generation is projected to grow in line with energy demand. By 2050, electricity is expected to contribute 35% of Australia's greenhouse gas emissions and 26% of global greenhouse gas emissions.[ii]

Emissions intensity varies significantly between different forms of generation. Natural gas fuelled generation is about half as intensive as coal. Wind and hydro result in close to zero emissions in operation.

While being part of an emissions intensive supply chain, energy transmission and distribution networks (the infrastructure used to transport electricity and gas) have comparatively low direct emissions.

The main sources of emissions from electricity network assets are:

- Indirect emissions associated with system losses – emissions associated with the generation of electricity lost in the process of transmitting the energy across the network.
- Direct emissions of sulphur hexafluoride (SF_6) emissions – a particularly potent greenhouse gas which is used as an electrical insulant.

The only significant direct source of greenhouse gas emissions from gas networks is due to gas leakage, with older or deteriorating pipelines leaking more than new and well-maintained pipelines. While overall gas leakage is not significant, the emissions are of a high potency. Methane, the primary component of natural gas, is a greenhouse gas with 21 times the warming potential of carbon dioxide.[iii] Australian gas industry estimates suggest that gas unaccounted for (i.e. the difference between gas produced and gas that reaches its end user) is approximately 2.5% in the Australian network.[iv] Much of this difference is due to metering errors, with some leakage primarily in distribution networks, which operate at lower pressures than transmission networks.

2. Energy Infrastructure Sector Overview

As at December 2006, the assets held in the Australian utility sector are estimated to be worth approximately $95 billion,[v] incorporating:

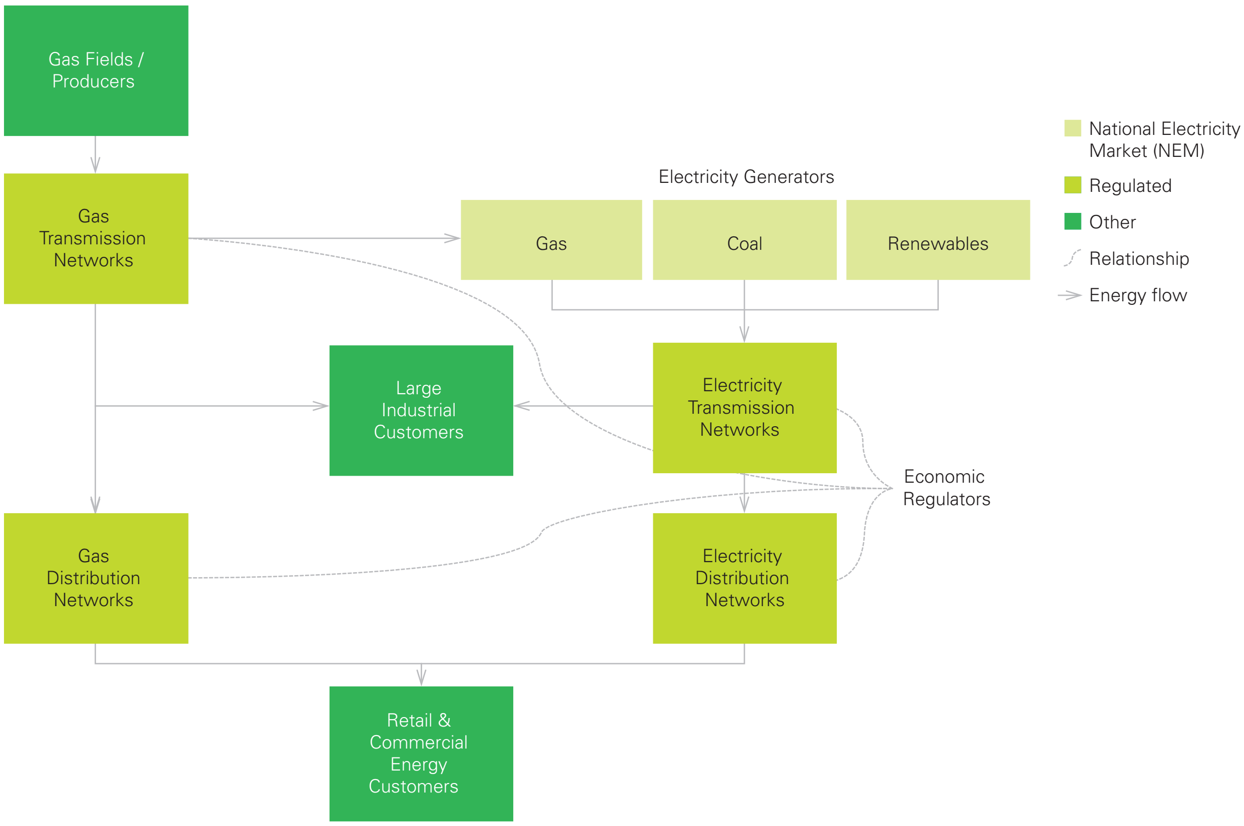
- A total regulatory asset base for regulated utility assets of approximately $50 billion, including electricity transmission and distribution assets and gas transmission and distribution assets; and
- An estimated value of electricity generation assets of $45 billion.

The energy market in Australia has a large number of stakeholders in addition to investors. Chart 1 provides an overview of the electricity and gas industries in New South Wales, Victoria, Queensland, and Tasmania. The National Electricity Market (NEM) does not operate in Western Australia or Northern Territory.

In most Australian states, some energy infrastructure assets are publicly held. In Victoria and South Australia all energy infrastructure, formerly publicly held, has been privatised. Holdings of private investors in energy infrastructure range from single assets through to integrated utility companies holding a portfolio of interests with varying degrees of vertical integration, from upstream production (gas fields and electricity generation) through to networks and retailing.

In recent years there has been significant activity in the energy sector, in the form of further privatisation, listing of assets, and consolidation. Investors are generally attracted to the sector because of the regulated return it provides (for network assets), within a mature and stable regulatory environment, resulting in stable cash flows for investors.

Chart 1: Electricity and Gas Industry Overview



2. Energy Infrastructure Sector Overview

2.1 Economic Regulation

Climate change risks result in different exposures for different types of energy infrastructure assets, with impacts on earnings being strongly influenced by the economic regulatory arrangements that apply.

Generation assets are not generally subject to economic regulation of prices or returns. Many privately held electricity generation assets in Australia are part of the National Electricity Market (NEM), a competitive, wholesale, spot market for electricity that covers five Australian states. Long-term negotiated energy supply contracts between generators and large energy users (including smelters and other large mining or minerals processing facilities) are also common, where both volumes and/or prices may be fixed for the term of the contract.

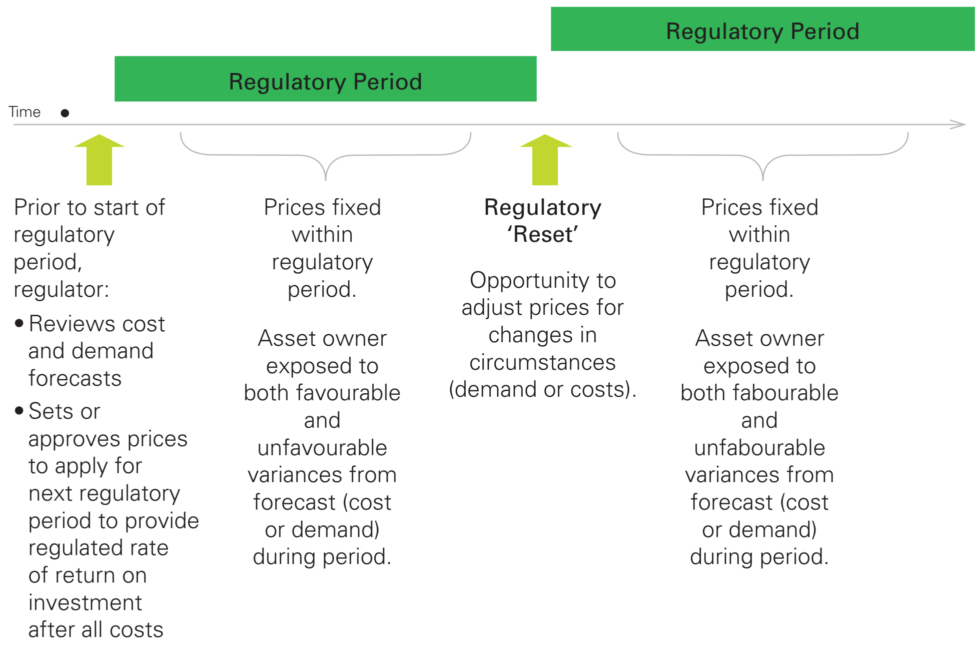
For electricity and gas transmission and distribution networks, the rate of return on investment is generally determined by economic regulatory regimes. Under these regimes, tariffs (prices) are set based on forecast demand, such that the returns on the investment (after costs) are largely fixed for a period (typically 5 years). The prices are reviewed at the end of each regulatory period, having regard to the costs of operating the business (including capital, operating, and financing costs) and demand for the infrastructure. As such, there exists potential at regulatory review dates ('resets') to take account of significant movements (up or down) in costs and demand, thereby, potentially reducing the volatility of returns to investors.

Typically, special rules apply in determining the amount of capital invested, on which returns are calculated. The value of capital invested as assessed by the regulator is commonly referred to as the Regulatory Asset Base ('RAB') in Australia.

Until recently economic regulation of energy assets was primarily on a state basis. However, going forward the federal Australian Energy Regulator is to be responsible for economic regulation of most gas and electricity infrastructure nationally (except Western Australia).

Chart 2 presents a simplified overview of a typical economic regulation process.

Chart 2: Simplified Overview of 'Typical' Economic Regulation Process



2. Energy Infrastructure Sector Overview

Where economic regulatory arrangements provide for a set return:

- In the short term if the forecasts of expenses or demand prove to be inaccurate, there is usually limited or no ability to review prices until the next regulatory review. Thus, the asset owner is exposed to the impact (positive or negative) of any variance between forecasts and actual outcomes.
- In the longer term prices are likely to be adjusted to take account of altered costs and demand, thus, limiting the impact on returns to owners.

Hence, a significant proportion of both positive and negative exposure from changes in demand or operating costs, such as those caused by climate change impacts, may be limited to the impacts within the regulatory period. In some cases, including electricity transmission networks in Australia, annual adjustments to tariffs occur based on actual demand, such that the revenues do not differ greatly from those forecast and approved by the regulator.

Notwithstanding the fact that allowed revenues are adjusted for changes in demand, climate change does have the potential to affect returns to investors. In Australia, most regulated infrastructure investments are traded at enterprise values exceeding their Regulated Asset Base (referred to as a RAB multiple). For example, in their half-year results in September 2006, SP Ausnet listed their implied multiple of enterprise value as 1.48 times the RAB.[vi]

While there are a number of different explanations as to why this value relationship arises, such as to incentivise investment in the network or due to cost advantages generated by owners, the result is that every additional dollar of capital investment has the potential to earn a slight return premium. Thus, for each dollar invested in assets and recognised in the RAB, the impact on enterprise value is more than one dollar. Thus, if climate change leads to impacts on network growth (and, hence, the investment in the asset base) this may have a multiplier impact on value.

3. Impact of Climate Change on Energy Infrastructure

The key climate change exposures for the energy infrastructure sector are considered to be:

- Carbon price risk and the associated impact of carbon prices and other factors on market prices for electricity;
- Climatic changes / changes in weather patterns – such as changes in average or peak temperatures; and
- Climate change related litigation.

3.1 Carbon Price Impacts

The financial impact of a carbon price on energy infrastructure investments will vary depending on the details of design and implementation of the scheme.

Carbon trading schemes fall into two broad categories:

- Cap and trade; and
- Baseline and credit.

Cap and trade schemes involve:

- Setting an emissions 'cap' – the maximum amount of greenhouse gas emissions allowable in a given period. The difference between the cap and 'business as usual' emissions is the targeted reduction in emissions. It is common for carbon trading proposals to involve modest reduction targets initially, with progressively more stringent targets over time.
- Creating tradeable permits ('carbon credits') for the allowable emissions, i.e. a right to emit. Typically a permit will be for one tonne of carbon dioxide equivalent greenhouse gas emissions (1 tCO_2-e).
- Allocating tradeable permits to affected parties.

Liable parties are required to surrender sufficient permits at the end of each period to cover all of their actual emissions. Liable parties who are able to reduce their emissions below the level of emissions for which they have permits are able to sell excess permits on market. The European Union Emissions Trading Scheme (EU ETS) is an example of a cap and trade scheme.

Under a baseline and credit scheme, liable parties are assigned an emissions path or 'baseline' which sets out allowable greenhouse gas emissions over time. The difference between the baseline and business as usual emissions is the targeted reduction in emissions. Tradeable permits are allocated with reference to the baseline. The NSW Greenhouse Gas Abatement Scheme is an example of a baseline and credit scheme.

In practice, there are many similarities between the two categories of schemes. As it is a proposed approach for Australia, the following analysis focuses on cap and trade schemes.

3.1.1 Electricity Generation

Electricity generation is particularly exposed to carbon price risk as it is typically the focus of carbon pricing proposals, due to:

- The size of emissions from this sector (38% of Australia's greenhouse gas emissions in 2004);
- The comparative administrative simplicity of applying a carbon pricing scheme to this sector (small number of sources with readily estimable emissions); and
- The low risk of import substitution.

Emissions from electricity generation may be the only sector covered by carbon pricing proposals. Alternately, emissions from other stationary combustion sources as well as emissions from industrial processes, fugitive emissions and emissions from transportation may be covered.

While, in theory, it would be possible to have a carbon pricing scheme that covered all sources of greenhouse gas emissions, this presents significant practical difficulties. For example, the costs and difficulties associated with measuring and monitoring greenhouse gas emissions from agriculture makes it unlikely that emissions from this sector would be included in any carbon pricing scheme. As yet, no economy-wide carbon pricing schemes have been implemented anywhere in the world.

Carbon pricing may be phased in – applying to a small number of sectors initially, with additional sectors included at a later stage. For example, the EU ETS initially imposed controls only on:

- Large electricity generation units (over 20MW);
- Oil refineries; and
- Manufacturers of iron and steel, cement, brick, tile, glass, pulp and paper.

Consideration is being given to expanding the EU ETS to other sectors, such as aviation, from the beginning of the second or third phase (2008 or 2013 respectively).

Where a carbon pricing regime is implemented, the cost of carbon becomes part of the marginal costs of supply, comprising both:

- Short Run Marginal Cost (SRMC): the cost of generating one unit of electricity (usually measured in terms of Megawatt Hours – MWhs) taking into account only the costs of operating the generator (excluding fixed costs).
- Long Run Marginal Cost (LRMC): the cost of generating one unit of electricity, taking into account all fixed overheads, such as financing and construction costs, as well as operating costs.

3. Impact of Climate Change on Energy Infrastructure

This presents different issues for existing generation assets than for investment decisions in new generation assets. However, in both cases, the key factors determining the impact of carbon pricing on different generation assets are:

- **Emissions intensity**: the extent which particular types of generation are responsible for greenhouse gas emissions, commonly measured as tonnes of carbon dioxide equivalent emissions per megawatt hour of electricity generated (tCO_2-e/MWh).
- **Permit allocation approach**: how permits are allocated to liable parties under the scheme.
- **Market price for electricity**. The market price for electricity is also impacted by carbon pricing and, in particular, by the permit allocation approach used.

The combined impact of carbon pricing on the cost of generation and on the market price for electricity determines the impact on earnings for a given generator.

Each of these factors is discussed below.

Emissions Intensity

The emissions intensity of generation depends primarily on the energy fuel source used. Table 1 lists the three most common energy sources used for electricity generation in Australia.

Table 1: Typical Greenhouse Gas Emissions Intensity and Costs of New Base-load Generation Using Different Fuels[vii]

	Black Coal	Brown Coal	Gas (CCGT)[viii]
Greenhouse gas emissions intensity (tCO_2-e/ MWh)	0.85	1.10	0.45
SRMC ($/MWh)	10	3	27
LRMC ($/MWh)	35	35	45

Note: Intensities and costs for a particular new generators vary due to technology and fuel costs.

Based on these emission intensities, a carbon price would lead to significantly different cost increases for generation using different fuel sources. For example, a price of $10 per tCO_2-e would lead to a cost increase of:

- For black coal generation: $8.50 per MWh raising SRMC by 85% to $18.50 per MWh and LRMC by 24% to $43.50.
- For brown coal generation: $11 per MWh raising SRMC by 367% to $14 per MWh and LRMC by 31% to $46.00.
- For natural gas generation: $4.50 per MWh raising SRMC by 17% to $31.50 per MWh and LRMC by 10% to $49.50.

Thus, emissions, intensity influences the extent to which each generators costs rise with carbon pricing.

Permit Allocation

The permit allocation method influences both generation cost and market prices. The choice of allocation method determines how the costs of the carbon price will be distributed throughout the economy, and which industries and/or consumers will ultimately bear the cost. A variety of permit allocation methods can be used. Typically this will involve some combination of:

- Auctioning – where liable parties are required to pay a market price for tradeable permits through an auctioning process.
- 'Free' allowances – where permits are allocated to affected parties at no cost. Free allocations may be given as a form of compensation to those detrimentally affected by the introduction of a carbon price scheme, including liable parties (those participating in the scheme), as well as others affected by the scheme, such as large commercial users of electricity.

3. Impact of Climate Change on Energy Infrastructure

Chart 3: Cost of Carbon under Different Permit Allocation Approaches

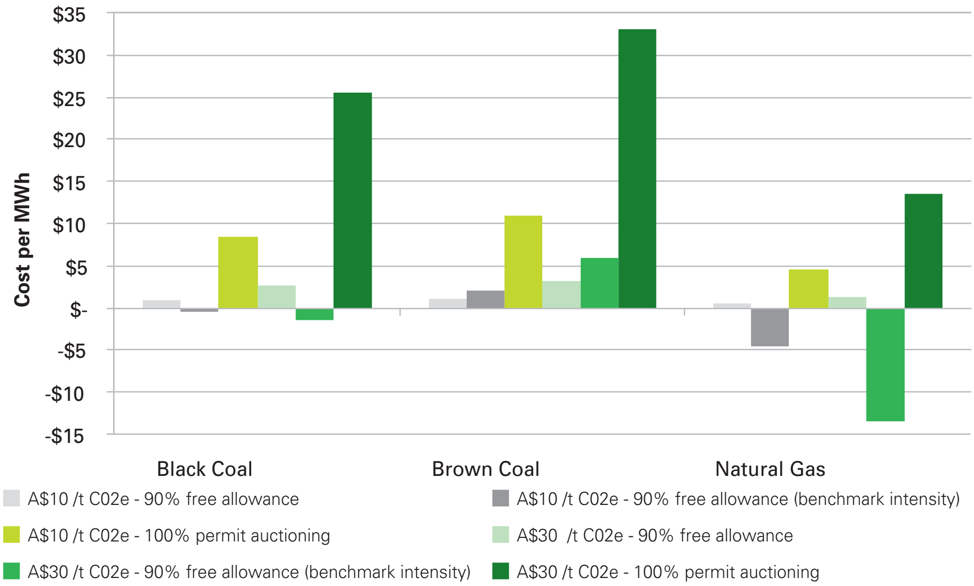


Chart 3 shows the potential cost of carbon for generators using different fuels under three possible permit allocation methods:

- 100% auctioning;
- 90% free allocation; and
- 90% free allocation with permits allocated based on a benchmark emissions intensity, such that the same number of permits is given to each generator for each MWh generated (in the example below permits are allocated at 90% of 1.0 tCO_2-e per MWh) irrespective of the actual intensity of the generator.

Thus, the larger the proportion of free allowances, the lower the cost increase experienced by the generator. Under a benchmark intensity allocation approach, generators that have emissions intensity below the benchmark can sell excess permits into the permit market.

Despite the fact that free allocations result in smaller impacts on generation costs, experience with the EU ETS, where allocation of free permits were given up front and not linked to electricity generation, shows that prices may rise by up to the same amount as under auctioning, as generators seek to keep the benefit of free allocations for themselves and pass on higher costs to consumers.

Under the first phase of EU ETS, each liable party was granted free allowances for the bulk of expected emissions. Thus, each had only a small net liability and was facing only a small increase in costs to meet the liability under the scheme. However, each of the free allowances has a value – it can be sold at the prevailing carbon price. Liable parties took the value associated with the free allowances into account when setting prices for sales after the scheme was introduced. Where they could raise prices to compensate for the lost opportunity to sell the free allowances, they did so, leading to larger price increases than were necessary to cover underlying cost increases (known as 'opportunity cost pricing').

In the case of electricity, generators have been highly successful in achieving price increases due to the relative inelasticity of electricity demand (that is, price rises typically result in only small decreases in consumption). Thus, the EU scheme design has resulted in a windfall profit for many generators, estimated to total £800 million p.a. in phase one (2005-2007) of the EU ETS for the UK power generation sector.[ix]

Different approaches to distributing the free allocation have the potential to reduce or eliminate such windfall profits. Under the EU ETS, free allocations were made on the basis of the generator's historical emissions – permits are allocated to individual generators based on that generator's actual historical emissions (i.e. more greenhouse-intensive generators receive more permits).

3. Impact of Climate Change on Energy Infrastructure

An alternative is to allocate permits based on benchmark emission intensity, as seen in Chart 3. Benchmark emission intensity allocation results in generators with higher emissions intensities receiving fewer permits than under historical emissions allocation, decreasing the potential for windfall gains. Thus, benchmark emissions intensity allocation should result in lower market prices and lower windfall profits than historical emissions intensity allocation. In addition, opportunity cost pricing will also be reduced by allocating permits subsequent to and conditional on actual generation in a particular period.

Thus, the specific permit allocation method is a key determinant of the impact of carbon pricing on generator earnings.

Market Prices

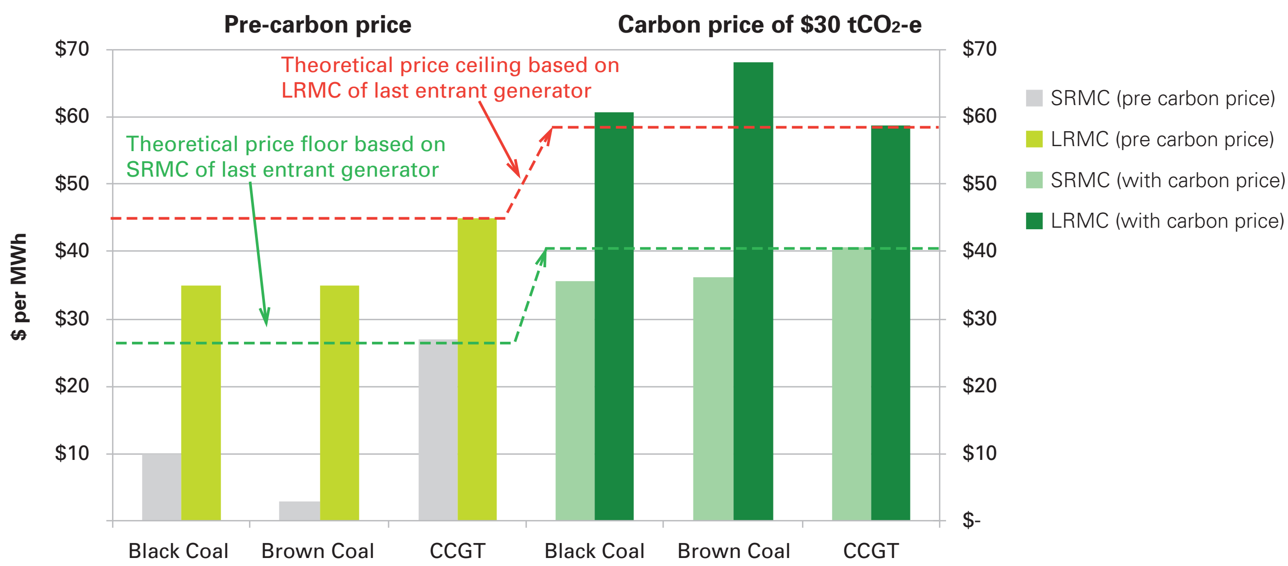
The market price for electricity influences the extent to which the cost of carbon can be passed through to customers. The market price for electricity is determined by the interaction of a large number of complex factors.[x] Two of the key determining factors are the short and long run marginal cost of generators in the market, which form a range of potential market price outcomes:

- At the lower end of the range: Existing generators will be willing to sell electricity at prices equal to or greater than their SRMC. Below this price, generators would choose not to operate, rather than produce electricity at less than their cost to generate. Demand from the NEM will be met first by the generator with the lowest SRMC. Once demand exceeds that generator's capacity, the generator with the next lowest SRMC will meet the balance of demand, and so on. **Thus, the market price for electricity will generally be at least equal to the SRMC of the last generator required to meet market demand.**
- At the upper end of the range: Where there is an excess of demand over supply, prices will rise to the point at which new generation is stimulated to enter the market. Given that generation assets have long useful lives, any decision about investment in new generation capacity will consider the long-term costs expected to arise over the asset's useful life. Hence, new investment will only occur where market prices for electricity are expected to exceed the LRMC. **Thus, the market price for electricity will generally not exceed the LRMC of the last entrant generator.**

As discussed above, carbon prices will change costs to generate electricity and change both SRMC and LRMC. Thus, the minimum price at which each generator is willing to sell their electricity will change, as will the upper range at which new generation will enter the market.

Chart 4 shows the change in the SRMC and LRMC for generation with different fuels in a situation where no free allowances are provided to existing or new generators. Marginal costs are as per the table 'Typical Greenhouse Gas Emissions Intensity and Costs of New Base-load Generation Using Different Fuels' presented in Table 1. In each case, the range of potential market price outcomes is shown as the range between the floor and ceiling price (green and red dashed lines).

Chart 4: Cost of Generation – 0% Free Allowances[xi]



3. Impact of Climate Change on Energy Infrastructure

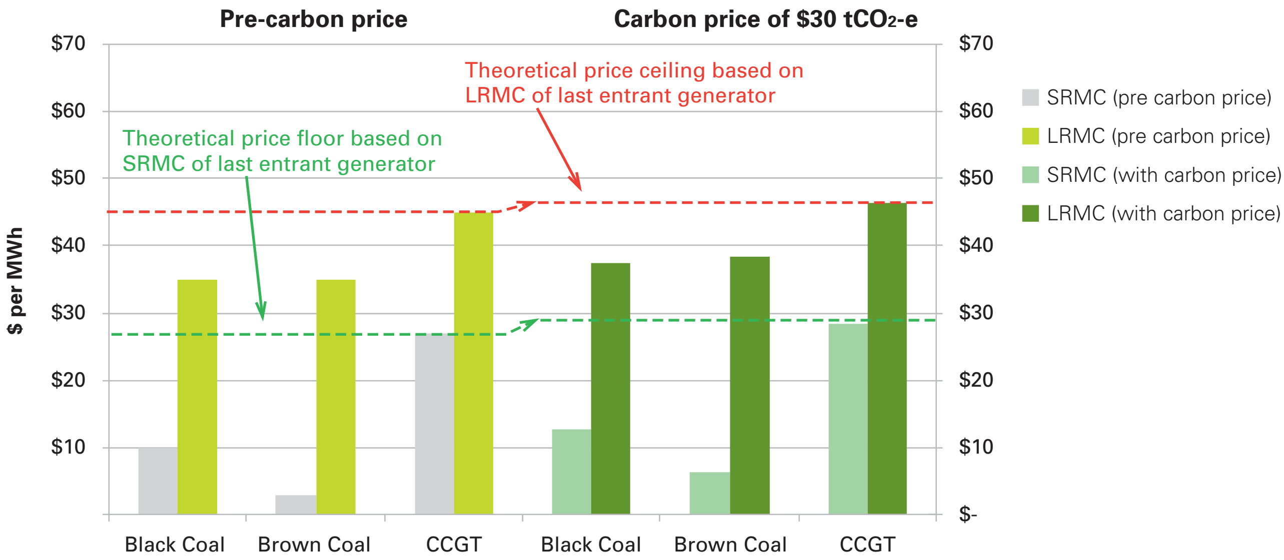
Charts 4 and 5 show that with no price for carbon, brown coal is the cheapest form of generation (in terms of its SRMC) and will be the first to dispatch electricity. Black coal and brown coal are on a par and are the cheapest in terms of their LRMC and, hence, would be preferred to other forms of new generation capacity, other things being equal.

- At a carbon price of \$30 per tonne of CO_2-e with 100% auctioning (see Chart 4), black coal's SRMC is slightly lower than brown coal's and black coal is, therefore, the first to dispatch electricity. Gas (CCGT) has become the cheapest form of new generation based on LRMC.

As shown in Chart 5, free allowances reduce the cost impact proportionately. Thus, under a scenario where there are 90% free allowances and a carbon price of \$30 per tonne CO_2-e:

- Brown coal continues to have the lowest SRMC and is still the first to dispatch electricity.
- Black coal's LRMC is slightly lower than brown coal's and, thus, black coal would become the preferred form of new generation capacity, other things being equal.

Chart 5: Cost of Generation – 90% Free Allowances[xii]



3. Impact of Climate Change on Energy Infrastructure

Chart 6: Cost of Generation – 90% Free Allowances (Benchmark Intensity Allocation)[xiii]

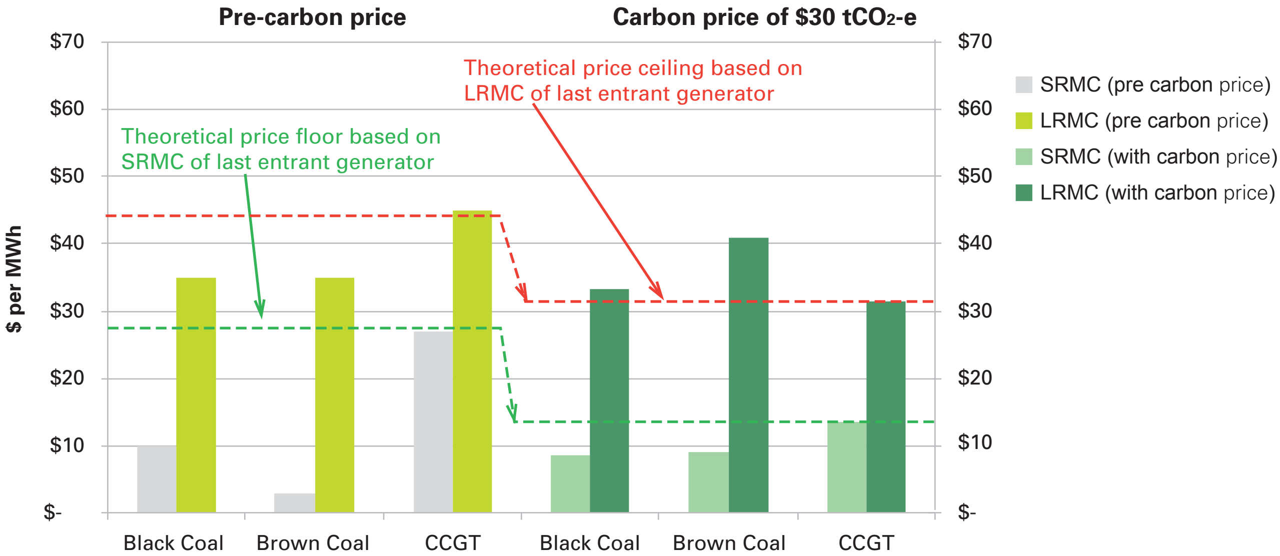


Chart 6 shows the impact of free allowances allocated on a benchmark intensity basis, assuming a benchmark intensity of 1.0 tCO_2-e per MWh. Under a scenario where there are 90% free allowances allocated on a benchmark intensity basis and a carbon price of $30 per tonne CO_2-e:

- The differences between the respective SRMC's and LRMC's under the different types of generation are the same as under the auctioning scenario (see Chart 4), even though the absolute costs are significantly lower.
- The benefit of free allocation is passed through to electricity consumers, while the net impact on operating profit per MWh is the same as under auctioning scenario for all types of generation.
- Black coal has the lowest SRMC (displacing brown coal) and is the first to dispatch electricity.
- CCGT's LRMC is the lowest and, thus, CCGT would become the preferred form of new generation capacity, other things being equal.

Market prices are based on a number of different drivers, of which the potential carbon price is but one. Overall, the market price is determined by the interaction of demand and supply, with both being subject to a number of factors.

- Demand for power is influenced by, for example:
  - Weather: warmer weather often leads to spikes in demand as air-conditioners are increasingly used.
  - Long term trends: such as population growth and growth in major industrial customers with significant power requirements.
  - Holidays: holidays and rostered days off generally lead to less demand than periods when industry is operating at full capacity.
- Supply from generators is influenced by, for example:
  - Weather: recently drought has led to a lack of water for cooling used in the generation process, leading to constrained output from affected generators.
  - Maintenance: routine maintenance can take a generator off-line, reducing supply.

3. Impact of Climate Change on Energy Infrastructure

Impact on Existing Generation
All generators (other than those whose electricity is sold under contract) receive the market price for their electricity. Thus, different generators will achieve different gross profit margins or EBITDA (being the difference between the market price and their own SRMC).

As indicated in Charts 4-6 the presence of a carbon price will affect both the SRMC and the market price for electricity, which in turn has the potential to change the earnings for each generator, depending on their emissions intensity.

As discussed previously in addition to the carbon price itself, the magnitude of the impact will be largely dependent on the permit allocation method, and the resultant behaviour of generators. In particular:

- **If permits are auctioned** to existing generators: the carbon price becomes a cash cost that generators must recover in order to remain profitable. This is particularly relevant in the case where carbon prices increase significantly to the point where market electricity prices will be insufficient to cover the carbon-inclusive SRMC of coal-fired generators.

  In such extreme scenarios, the order in which installed generation assets come into service to meet customer demand may change significantly. Some lower-emission generation technologies may become sufficiently profitable to run as base-load capacity. More greenhouse-intensive plants may cease to provide base-load generation, operating only when the electricity price is sufficiently high to cover their carbon-inclusive SRMC. If the start-up time for the greenhouse-intensive generation plant is too long to take advantage of short-term spikes in peak market prices these plants may not generate at all.

- **If permits are distributed via a free allocation** mechanism: the impact will depend on whether permits are given upfront or conditional on the generation of electricity.

  If the permits are distributed upfront, the carbon price is only an opportunity cost, as generators have not had to pay anything for the permits. In this situation, generators may seek to recover this opportunity cost through increased electricity prices, despite the fact that their underlying costs have not increased. The extent to which generators pass through the opportunity cost to energy purchasers is likely to be driven by the permit allocation method (as discussed previously) and the extent of competition in the market. For example:

  - Where there is an excess of supply of electricity and strong competition between generators, the generators have less ability to pass through the costs (i.e. buyers market):
  - Where there is an excess of demand for electricity, such as currently exists in the NEM, it is likely that a large proportion of the carbon opportunity cost will be passed through to customers unless the scheme design prevents such action.

  If the permits are distributed subsequent to and conditional on the generation of the electricity, then the carbon price becomes an additional operating cost and the net impact on operating profit per MWh for any individual generating asset will be the same as under the auctioning case.

Impact on New Investment
Where carbon pricing is anticipated, the cost of carbon would be considered as one of the future costs that must be able to be recovered for new investment in generation to proceed.

As shown, emissions intensity varies between different forms of generation. As such carbon pricing has the potential to impact on the competitive economics of alternative forms of generation and influence decisions about the form of generation in which to invest.

Without carbon pricing, black coal and brown coal are the cheapest forms of generation and so, other things being equal, investors would choose to invest in these technologies. However, in the presence of a carbon price this decision may change.

3. Impact of Climate Change on Energy Infrastructure

Assuming 100% auctioning of permits (and hence that generators bear the full cost of carbon pricing):

- At a carbon prices less than $10 per tonne of CO_2-e the LRMC of generation from gas (CCGT) is higher than both brown coal and black coal.
- However at $30 per tonne of CO_2-e gas (CCGT) generation is the cheapest (i.e., has the lowest LRMC). Thus, if investors expected that future carbon prices would be equal to or greater than $30 per tonne of CO_2-e, they would choose to invest in gas (CCGT) rather than black or brown coal.
- For the preferred form of electricity generation (with lowest LRMC) to be non-fossil fuel based such as nuclear or renewables, the carbon price must be well in excess of $30 per tonne of CO_2-e in the absence of any other measures to encourage investment in these technologies.

Thus, in the longer term, carbon pricing or policy measures are expected to shift new investment from coal to natural gas, the next most competitive generation technology, due to gas' significantly lower emissions intensity.

Other Policies

The interaction of policy measures other than carbon pricing may influence choices about investment in new generation. For example, environmental approvals may prevent investment in more greenhouse-intensive generation technologies, regardless of whether they are the lowest cost form of generation. Incentives (for example Renewable Energy Credits)[xiv] may make low-emissions technologies more economically competitive, even in the absence of high carbon prices.

Uncertainty

Electricity generation assets have useful lives in the range of 30-50 years. Where it is unclear whether carbon will be priced within the life of the asset, the form carbon pricing will take, and what carbon prices are likely to be, additional uncertainty is created for investors. This uncertainty may alter investor behaviour in respect of the timing and quantum of their investment decisions. For example:

- Investors may potentially delay investment in new electricity generation capacity.
- The relative riskiness of investment decisions may be impacted. For example, in the case presented above, at carbon prices well below $30 per tonne of CO_2-e where no free allocations exist, an investor would still prefer coal technology having regard to the expected return alone. However, if there was risk that the carbon price may increase, it is likely that the investor would seek to manage this risk by investing in the lower emission technology. Alternatively, investors may seek an additional return for investing in a technology which could give rise to more risk in the future.

3.1.2 Electricity Transmission and Distribution Networks

Carbon pricing of emissions from electricity generation may also affect electricity transmission and distribution networks. If carbon pricing results in an increase in the cost of electricity, this may reduce demand and thus, decrease network revenue. However, the impact on electricity networks is likely to be reduced significantly by the tariff adjustment mechanism provided under the economic regulatory arrangements (particularly if tariffs are adjusted for demand changes annually as with some electricity transmission networks). For all networks, it is anticipated that the impact is likely to be accounted for in the next regulatory review.

Thus, the key value exposure relates to the potential for carbon pricing to impact on long-term demand forecasts and, in particular, peak demand, which is the key driver of network growth requirements.

On the other hand, growing awareness of climate change, along with technological advances and possible policy responses, may lead to an increase in development of low emissions sources of electricity, such as wind, nuclear, solar, or geothermal. These power plants are likely to be located in remote areas of Australia. From the perspective of transmission network owners and developers, this may provide new opportunities in connecting these remote assets into the network.

Thus, the overall impact of carbon pricing on electricity transmission and distribution will depend on whether the negative impact from a possible reduction in electricity demand due to carbon pricing exceeds the likely positive impact from connections of new low emission generators.

The impact of carbon pricing on electricity transmission and distribution is modelled, together with other climate change risks, in section 3.4 below.

3. Impact of Climate Change on Energy Infrastructure

3.1.3 Gas Transmission and Distribution Networks

Carbon pricing of emissions in production or use of gas has the potential to raise the price of gas and thus, lead to reductions in demand. However, it is expected that any negative impact would be far outweighed by the positive impacts from gas having a lower greenhouse-intensity that other fossil fuels. That is, carbon pricing would result in a much larger increase in cost for the key alternatives to natural gas, such as coal.

Demand for natural gas is forecast to increase substantially (by 2.8% per annum between 2003 and 2030), taking into account current policy measures only.[xv] This growth is led by increases in gas-fired electricity generation as new, more efficient combined cycle technology is commercialised. Gas demand for electricity generation accounts for 34% of this forecast growth.

Due to their lower emission intensities, gas and renewables become more competitive relative to coal as carbon prices increase. As such, when carbon pricing measures are introduced, gas fired generation is expected to further expand and these gas demand growth forecasts would be exceeded. Thus, carbon pricing could result in additional investment in the gas transmission networks to which such assets are connected beyond that currently anticipated. The potential for additional network growth and capital expenditure may lead to positive impacts on value, because each dollar invested in transmission assets would be expected to lead to a more than a one dollar increase in value. Transmission assets in particular are expected to benefit, as generation assets are often directly connected to the transmission network.

The impact of carbon pricing on networks is modelled, together with other climate change risks, in section 3.4 below.

3.2 Impacts From Climatic Changes/ Changes In Weather Patterns

Increased average temperatures and more frequent extreme weather events from climate change are expected to drive changes in the pattern of demand for energy and may result in damage to or even loss of assets.[xvi]

3.2.1 Electricity Generation

Peaks in electricity demand occur on hot summer days, primarily linked to increased domestic demand for cooling. Peak demand is forecast to grow at a faster rate than total demand, with an increasing proportion of homes having air conditioning installed.[xvii]

Climate change is expected to result in an increase in the number of extreme hot days experienced. More frequent extreme hot days may lead to more frequent (and potentially larger) electricity peak demand events, accentuating the tendency for peak demand to grow at a faster rate than total demand. However, peak demand growth may be constrained by other policy measures, including those designed to improve the energy efficiency of homes, advanced metering and load control arrangements. So, the extent of growth is uncertain.

Within the NEM, peak demand results in very high spot prices for electricity traded during these peak times. Therefore, more frequent peak events could also result in increased gross profit margins for generators exposed to spot prices. ‘Peaking plants’ that is, generators that can switch on or off rapidly to supply short term spikes in demand, in particular, may benefit. Such impacts will depend on supply-demand balances at the time. Notwithstanding, increased peak demand is expected to have minimal impact on existing electricity generation assets.

Another potential weather-related impact, which has recently been seen in Queensland, is limited water supply restricting the output of electricity generators where water is a key input into their production process. Some newer generation facilities have sought to mitigate this risk through technological development of processes which may significantly reduce water resource demands.

3. Impact of Climate Change on Energy Infrastructure

3.2.2 Electricity Transmission and Distribution Networks

It is expected that any revenue or expense impact from climatic changes would be adjusted for at the next economic regulatory review. Thus, the value exposure is largely limited to the impact on long-term demand and network growth forecasts.

The economic regulatory arrangements that govern electricity transmission and distribution infrastructure require that the network is able to meet the maximum (peak) demand expected, to minimise the risk of supply interruptions. Thus, network growth and capital expenditure requirements for electricity networks are linked to the level of peak demand. Climate change, which is expected to contribute to increasing peak demand, may require increased network investment.

The need for additional network expenditure may be further accentuated by the physical constraints of electricity networks. The carrying capacity of electricity networks (lines and transformers) is reduced when ambient temperature are high – a warming of 1°C can lead to a 3% decrease in efficiency.[xviii] Thus, given that peak electricity demand is likely to occur at times of high ambient temperature, the total capital expenditure requirements to meet peak demand are likely to be further increased.

Overall, changes in weather patterns from climate change are likely to result in an increased need for investment in electricity networks. Because each dollar invested in network assets is expected to result in more than a one dollar increase in equity value, this should result in positive valuation impacts for electricity network investments.

However, the potential benefit from increased network growth may be limited by additional requirements to pursue alternatives to network expansion, such as facilitating embedded generation or installing advanced metering.

The impact of climatic changes on networks is modelled, together with other climate change risks, in section 3.4 below.

3.2.3 Gas Transmission and Distribution Networks

For gas, peak domestic demand in southern states, such as South Australia and Victoria, traditionally occurs in winter, linked to heating demand. Climate change is expected to result in more mild winters, which could lead to a decline in domestic heating demand.

While residential demand is only a small component of total gas demand (forecast to be 10.2% of overall gas demand by 2030[xix]), the impact may be significant for particular assets. Distribution assets generally have a much greater exposure to domestic demand than transmission assets (which also supply large-scale industry and electricity generators) and the impact is expected to vary between regions.

It is also possible that, with warmer average and peak temperatures, the capacity of gas pipelines could be reduced as gas expands at higher temperature, reducing throughput. This will either:

- Reduce the carrying capacity of the pipeline; or
- Increase the costs associated with maintaining the existing throughput.

Because additional electricity demand experienced at peak times is typically met by gas-fired generators, an increase in peak electricity demand may result in increased attractiveness of investment in gas fired peaking plant capacity. As noted above, additional demand for gas due to electricity generation requires additional network investment, and this has potential for positive impacts on value. In addition, government policies relating to increasing domestic use of gas appliances may also have a positive impact.

Overall, as with electricity networks, it is expected that any revenue or expense impact would be adjusted for at the next economic regulatory review. Thus, the value exposure is largely limited to the impact on long-term demand and network growth forecasts.

The impact of climatic changes on networks is modelled, together with other climate change risks, in section 3.4 below.

3. Impact of Climate Change on Energy Infrastructure

3.3 Climate Change Litigation

Climate change litigation can involve actions against:

- Governments – seeking to influence policy or force action to limit greenhouse gas emissions, such as requiring climate change to be considered in environmental approval processes; or
- Businesses – seeking to impose liability for their contribution to climate change, following the example of tobacco and asbestos cases.

These risks were highlighted in a decision handed down by the US Supreme Court on 2 April 2007, which found that greenhouse gas emissions from automobiles were 'air pollutants' capable of causing damage to the plaintiff states. As a result, the US Environment Protection Agency is required to provide compelling reasons for continuing not to regulate to control their release.

Litigation risk is most significant where the asset is considered to be greenhouse intensive. Thus, fossil fuel electricity generation is particularly exposed, especially for new projects where governmental and other approvals are required.

Community concern is increasingly being mobilised in relation to new greenhouse-intensive energy investments, exemplified by the initiation of legal action to oppose developments. In Australia, public concern about climate change led to:

- Rejection of the Redbank 2 coal-fired power plant proposal in NSW; and
- A requirement for investment in greenhouse gas emission reduction as part of the approval of the extension of the life of the Hazelwood power plant in Victoria.

Ultimately, changes in public policy may prevent new greenhouse-intensive developments going ahead or force the closure of current plants before investors would otherwise choose to do so. Showing leadership on climate change, in particular by taking action to minimise emissions where possible, can help to reduce exposure to this risk.

3.4 Summary Of Climate Change Impacts

Climate change is expected to lead to a mixture of positive and negative impacts on energy infrastructure assets. Key sources of exposure relate to:

- Indirect impacts of carbon pricing on demand; and
- Climate change impacts on demand and network performance.

Many of the impacts are interrelated. For example, higher average ambient temperatures may reduce gas demand for heating (reducing need for network investment) at the same time as it reduces the carrying capacity of gas lines (increasing the need for network investment).

To capture these interrelationships, modelling for transmission and distribution assets has been conducted for assets considering all of the key climate change exposures for that asset type.

3.4.1 Electricity Generation

Modelling the complex demand and supply relationships in the electricity spot market and resultant change that a carbon pricing regime may have on the spot price of electricity is beyond the scope of this report. Accordingly, no earnings modelling has been carried out for electricity generation. Section 3.1.1 above presents modelling of the impacts that a carbon pricing regime could have on electricity generators' costs and a discussion of potential earnings impacts.

3.4.2 Electricity Transmission and Distribution Networks

For electricity networks, the combined impact of the following exposures has been modelled:

- Carbon pricing of emissions from electricity generation or widespread implementation of energy efficiency measures, leads to an overall reduction in demand for electricity and network growth relative to the Business As Usual ("BAU") case. A reduction in overall demand growth by 0.6% p.a. through to 2030 has been assumed. This is equivalent to the 2030 demand for electricity being 15% below BAU electricity demand in 2030.[xx] This leads to a reduction in the rate of network growth of:
  - -0.6% p.a. for transmission; and
  - -0.5% p.a. for distribution.

  Differences reflect the different exposure of these assets to residential demand (which has lower demand elasticity).

3. Impact of Climate Change on Energy Infrastructure

- Increases in the frequency of extreme hot days lead to an increase in peak demand. An increase in peak demand growth of an additional 0.4% p.a. has been assumed.[xxi] This leads to increases in the rate of network growth of:
  – +0.4% p.a. for transmission; and
  – +0.7% p.a. for distribution.
  Differences reflect the different exposure of these assets to residential cooling demand.
- Increases in average temperatures lead to a reduction in line efficiency. A reduction in efficiency of 3% over the next 30 years has been assumed, leading to increases in the rate of network growth of +0.1% p.a. for both transmission and distribution.
- The combined impact of these effects on network growth is:
  – -0.1% p.a. for transmission; and
  – +0.3% p.a. for distribution.

Results are presented in Table 2, as changes in the RAB multiple using a rate of return regulatory model, based on the broad regulatory principles that exist for Australian electricity transmission and distribution assets. A central estimate is presented for all transmission and distribution networks, as there are not considered to be significant differences in the impacts on different geographical networks. Further details of the modelling approach are appended.

Table 2: Impact of Climate Change Risk on Electricity Transmission and Distribution Assets

Exposure	Impact on RAB Multiple	% change on RAB Multiple
Electricity Transmission		
Reduced overall demand	-0.006 x	-0.48%
Increased peak demand	+0.004 x	+0.32%
Decrease in transmission efficiency	+0.001 x	+0.08%
Total	-0.001 x	-0.08%
Electricity Distribution		
Reduced overall demand	-0.005 x	-0.38%
Increased peak demand	+0.007 x	+0.53%
Decrease in transmission efficiency	+0.001 x	+0.08%
Total	+0.003 x	+0.23%

The impacts presented are the sum of each type of climate change exposure to which the asset is subject. Because there are both positive and negative impacts expected, the overall impact is reduced, and results are sensitive to the assumptions about the quantum of each impact. In addition, results are the impact that remains after taking into account the mitigating effects of economic regulation. Likewise, it should be noted in the early years demand-driven impacts may outweigh weather-related impacts.

For electricity transmission, the overall impact is slightly negative, as the decrease in overall demand for electricity due to carbon pricing is greater than the increased capacity requirements.

Electricity distribution experiences a slight positive impact as distribution has a greater proportion of residential demand and the increase in peak demand is driven by residential air conditioner use. This outweighs the overall decrease in demand due to higher electricity prices.

Overall modelled impacts ranged from -0.08% reduction in RAB for transmission and up to +0.23% increase in RAB for electricity distribution. The result of these offsetting exposures is that there is a low net impact.

3.4.3 Gas Transmission and Distribution Networks

For gas networks, the combined impact of the following exposures has been modelled:

- Carbon pricing of emissions from electricity generation leads to an increase in gas demand for electricity generation to 21% above that assumed in the base case by 2030.[xxiii] This, combined with the peakiness of such demand, leads to a change in network growth rates of +0.2% p.a. for transmission. This factor does not impact on distribution.
- Warmer average temperatures lead to a reduction in gas demand for heating. In southern States, a reduction of 20% below base case in domestic demand has been assumed.[xxiv] Thus, the impact on network growth rates for different networks is:
  – Up to -0.1% p.a. for transmission; and
  – Up to -0.4% p.a. for distribution.
- Retail demand (Australia wide) increases due to expected policy responses by government to encourage use of gas over other fossil fuels, due to its lower greenhouse intensity. This is assumed to result in an increase in distribution network growth of +0.1% per annum.

3. Impact of Climate Change on Energy Infrastructure

Modelling results are presented in Table 3, as changes in the RAB multiple, using a rate of return regulatory model based on the broad regulatory principles that exist for other Australian gas transmission and distribution assets.

A range of results is shown because impacts differ markedly between the southern states of Australia (where peak gas usage currently occurs in winter due to household heating) and the rest of Australia. Low and high values are from different assets which have different sensitivities to these risks.

Further details of the modelling approach are appended.

Table 3: Impact of Climate Change Risk on Gas Transmission and Distribution

Exposure	Impact on RAB Multiple	% change in RAB Multiple
Gas Transmission		
Increased demand (generation)	+0.002 x	+0.16%
Decreased winter demand	-0.001 to 0.000 x	-0.08% to 0.00%
Total	+0.001 to +0.002 x	+0.08% to +0.16%
Gas Distribution		
Decreased winter demand	-0.004 to 0.000 x	-0.32% to 0.00%
Increased demand (response to government policy)	+0.001 x	+0.08%
Total	-0.003 to +0.001 x	-0.24% to +0.08%

Impacts on RAB for different networks range from:

- +0.08% to +0.16% for gas transmission; and
- -0.24% to +0.08% for gas distribution.

Positive impacts are experienced where there is a small exposure to domestic demand so that the negative impact from lower residential demand during winter is overwhelmed by the positive impacts from:

- For distribution, government policy promoting gas; and
- For transmission, increasing numbers of gas-fuelled power stations.

Results are a combination of impacts from both negative and positive exposures after taking into account the mitigating effect of economic regulation. Thus, the overall impact is lower than exposure to particular factors. The impact for a particular network will largely depend on whether the asset is situated in a cooler Australian climate (impact more likely to be negative) or a warmer climate (impact more likely to be positive).

4. Assessing Exposure of Individual Assets/Companies to Climate Change Risk

In general, in assessing the exposure of an asset, company, or sector to a particular climate change risk, consideration should be given to how exposure varies with each of the following elements:

- Geography;
- Emissions intensity / technology;
- Ability to pass through cost; and
- Risk mitigation opportunities.

4.1 Geography

4.1.1 Carbon Pricing

The likelihood of carbon pricing being introduced differs between jurisdictions and thus, exposure depends on where emissions occur.

Generally, countries that have committed to greenhouse gas reduction targets under the Kyoto protocol present the highest likelihood of carbon pricing. However, there is no requirement on ratifying countries to establish domestic carbon pricing schemes and some ratifying nations intend to achieve their reductions without imposing any form of carbon price regulation. Equally, some jurisdictions that are not bound to reduction targets have introduced or proposed carbon trading.

Australia has not ratified the Kyoto protocol, but has nonetheless stated its intention of meeting its Kyoto target (of increasing emissions by no more than 8% over 1990 levels over the period 2008-2012). On 3 June 2007, the Prime Minister announced that Australia will introduce a national emissions trading system beginning no later than 2012.[xxv]

The likelihood of carbon price regulation can vary within a country – from region to region – where state and territory governments choose to implement carbon pricing where no national scheme is planned.

Accordingly, in assessing exposure to carbon price risk, it is necessary to gain an understanding of the jurisdictions in which significant emissions arise and the likelihood of carbon price regulation being introduced in those jurisdictions. Ideally, an emissions profile would be developed for each jurisdiction in which there is significant emissions, to facilitate exposure analysis.

4.1.2 Constraints on Power Networks

When a national emissions trading scheme is developed, the NEM will play a role in minimising geographic differences in impacts. However, limits to the interconnectivity between the various State electricity markets combined with differences in the existing dominant fuel source for power generation are likely to result in some difference in impacts on wholesale electricity prices in each State as a result of an emissions trading scheme.

Similarly, a key input into the wholesale electricity cost for combined cycle gas turbine generation is the price and availability of natural gas under long-term contracts, including the cost of the gas itself and the cost to transport it to the location required. The relative and absolute cost of gas and electricity transmission will affect the SRMC and LRMC for combine cycle gas turbine generation where either the gas resource or power station is located a long distance from their prime markets.

4. Assessing Exposure of Individual Assets/Companies to Climate Change Risk

Table 4: Changes in Climate by 2030 (Relative to 1990) for Regions of Australia
(Central estimates for low and high scenarios)[xxvi]

	Average Annual Temperature		Average Annual Number of Hot Days (>35ºC)		Extreme Daily Rainfall Intensity	
Region	**Low**	**High**	**Low**	**High**	**Low**	**High**
New South Wales	+0.6ºC	+1.3ºC	+1 day	+25 days	0%[B]	+6% (east)[B]
SE Queensland	+0.6ºC	+1.3ºC	0	+5 days*	0%[A]	+30%[A]
Southern SA	+0.4ºC	+0.9ºC	+2 days	+15 days*	0%[A]	+10%[A]
Tasmania	+0.5ºC	+1.1ºC	0	+1 day	+20%[B]	+80%[B]
Victoria	+0.5ºC	+1.1ºC	+1 day	+10 days*	+5%[A]	+70%[B]
SW Western Australia	+0.5ºC	+1.1ºC	+1 day	+20 days	N/A	N/A

N/A results not available * near coast [A]1 in 20 year event [B]1 in 40 Year event

4.1.3 Climatic Changes

The expected changes in climate from global warming vary significantly from region to region. Thus, in considering potential for climatic impacts, it is important to understand the specific impacts anticipated for the region or regions to which the asset or entity is exposed. Estimates of a selection of impacts are presented in Table 4 for regions of Australia.

4.2 Emissions Intensity/Technology

Greenhouse gas emissions intensity is a key driver of exposure to carbon price risk for generators. In addition to the fuel source for generation, the particular technology also influences emissions intensity (see Table 5). Thus, in assessing exposure of a particular generation asset to carbon price risk, it is important to understand the fuel source and the technology used.

Australia's composition of generation technologies is somewhat different to the global average. The dominant coal technology, subcritical pulverised coal, is relatively inefficient compared with more advanced coal technologies such as supercritical and ultra supercritical pulverised coal and, thus, has higher emissions.[xxix]

Table 5: Emissions Intensity of Common Electricity Generation Technologies

Technology	Carbon Dioxide Emissions (t/MWh)[xxvii]	Share of Australian Generation Capacity at 2006[xxviii]
Subcritical pulverised coal (black)	0.77-0.85	41.8%
Subcritical pulverised coal (brown)	1.1	16.3%
Supercritical pulverised coal	0.72	4.9%
Integrated coal gasification combined cycle	0.71-0.75	0.0%
Combined cycle gas turbine	0.34-0.43	4.5%
Other gas technologies	na	10.7%
Hydro	0	16.6%
Other renewables	0	0.2%
Other (including oil-fired)	na	5.0%

na = not available

Integrated gasification combined cycle (IGCC) power generation plants are a relatively new type of technology for power generation which uses coal gasification – one of a range of 'clean coal' technologies. IGCC offer some potential for reducing emissions from coal-fired generation, due to its higher efficiency.

Combined cycle gas turbine technology has significantly lower emissions than any of the coal technologies and this, along with its high levels of efficiency contribute to it now accounting for more than 50% of the worldwide market for new electricity generating capacity.[xxx]

4. Assessing Exposure of Individual Assets/Companies to Climate Change Risk

4.3 Ability to Pass Through Costs

4.3.1 Electricity Generation

For generation assets, the ability to pass through cost increases from climate change is determined by market forces as described in section 3.1.1. Thus, within the same market, there will not be a difference between generators in the ability to pass through cost. However, there may be differences between markets.

In Australia, despite the existence of a national electricity market involving generators in Queensland, NSW, Victoria, Tasmania, and South Australia, fuel costs, market demand, network capacity (in particular, the capacity of interstate interconnectors), and other factors result in state-based differentials in market prices. As such generators in different states may have different ability to pass through costs to energy purchasers.

Some generators supply under long term contracts and in these cases, pass through would be governed by the contract terms.

4.3.2 Transmission and Distribution Networks

The economic regulation regimes that typically apply to energy network investments govern cost pass through and hence, influence exposure to climate change risks that increase costs.

As explained in section 2, typical regulatory approaches allow for a regulated rate of return after allowing for all reasonable costs. Cost pass through by networks to customers will not cause negative impacts on returns, because the regulatory arrangements should safeguard a minimum level of return. Thus, exposure is expected to be limited to unanticipated cost increases within the regulatory period, until cost estimates can be revised at the next regulatory reset.

The extent of pass through by networks to energy consumers may vary between economic regulatory regimes, depending on each regulator's attitude with respect to changes in costs and revenues over the course of a regulatory period. However, as noted above in section 2.1, going forward, all Australian networks (other than those in WA) will come under the jurisdiction of a single regulator, which is likely to reduce differences between networks.

4.4 Risk Mitigation Opportunities

For generation assets, the cost of carbon pricing can be greatly reduced through reducing greenhouse gas emissions (also referred to as emissions abatement). Thus, in assessing exposure to carbon price risk it is important to understand the sector's or company's ability to reduce emissions. Greenhouse gas emissions abatement may also be a source of opportunity. Where reductions in excess of any mandatory requirements are able to be made, carbon credits can be created and sold, providing a new source of revenue.

Abatement potential is highly asset specific and depends on the particular technology and configuration in use. The Federal Government's Generator Efficiency Standards require existing generators to pursue efficiency improvements which will also lead to reductions in greenhouse gas emissions.[xxxi]

In the longer term, emerging technologies such as carbon capture and storage offer potential to reduce significantly coal-fired generation's emissions, potentially bringing emissions close to zero. However, the technology is still in the early stages of development and there is significant uncertainty about investment costs for commercial scale projects.[xxxii] Even if such technologies become available, there may be limited potential to retrofit such solutions to existing plants and the technology may be more easily compatible with some forms of generation than others. For example, carbon dioxide can be captured at a lower cost from an integrated coal gasification combined cycle power generation plants than from conventional pulverised coal fired power stations.[xxxiii]

The physical risk issues associated with water availability may be mitigated over time through new generation technologies. For example, the Kogan Creek Power Project in Queensland is employing an advanced supercritical technology and air cooling, which is expected to reduce water usage by 90% compared to current national averages.[xxxiv]

5. Summary and Conclusions

The exposure of energy infrastructure assets to climate change risk is driven by:

- The large contribution of the energy sector to total greenhouse gas emissions, particularly in Australia; and
- The relationship between changing climatic conditions and energy consumption.

However, this exposure is partially mitigated by:

- For generation assets, the inelasticity of demand for energy, which enables cost increases to be passed through to consumers with only minimal impacts on consumption.
- For energy networks, the economic regulatory arrangements that that safeguard the rate of return on assets.

Thus, much of the impact of climate change exposures is effectively shifted to energy consumers.

Analysis reveals that:

- For existing electricity generation, carbon price risk is the key immediate threat from climate change. The impact of carbon pricing on existing generators depends on:
  - Scheme design, in particular, the permit allocation approach adopted. Earnings impacts may be small or even favourable if a large proportion of permits are allocated for free, which is possible in the early years of trading.
  - Relative emissions intensity. Generators with the lowest emissions intensity will generally experience the smallest impact on earnings.
- For new generation, carbon price risk is expected to:
  - Delay new investment until there is reasonable certainty about future carbon prices.
  - Where carbon prices are sufficiently large, change preferences for different forms of generation. Modelling shows that at a carbon price above $30 without any free allocations, natural gas generation becomes the preferred form of new generation, displacing coal.
- For electricity and gas networks:
  - The 'rate of return' economic regulation that such assets are typically subject to plays an important role in mitigating most climate change risks, by allowing for periodic adjustments to prices to reflect changes in costs and demand to provide the asset owner with a reasonable return on investment.
  - Climate change has the greatest impact on value where it affects long-term peak demand forecasts and hence, network growth. This arises because network assets are typically valued at a multiple of the asset base recognised by the regulator (e.g., value = 1.48x RAB) so changes in network growth have a multiplier impact on value.
  - Climate change is expected to result in a mixture of positive and negative effects on network growth, from both climatic changes and flow on effects from carbon pricing of electricity generation emissions. The cumulative impact of these exposures, after taking into account the mitigating effect of economic regulation, is:

    Electricity transmission: -0.08% change in the RAB multiple with the most significant impact being moderation in the overall growth in electricity demand due to carbon pricing.

    Electricity distribution: +0.23% change in the RAB multiple, with the most significant impact being more frequent extreme hot weather events, which further stimulate the growth in air conditioning and, hence, peak demand.

    Gas transmission: +0.08% to +0.16% change in the RAB multiple for different networks, with the most significant impact being increasing use of gas for electricity generation.

    Gas distribution: -0.24 to +0.08% change in the RAB multiple for different networks. The most significant impact is in cooler climates where warmer winters are expected to decrease domestic heating demand.

Many climate change risks remain difficult to quantify. In part, this is due to uncertainty about the size, nature, and timing of impacts. However, the key impediment to investors analysing the impact of climate change risk on value at the company level is availability of the relevant information. While leading companies are voluntarily publicly reporting on greenhouse gas emissions, climate change exposure, mitigation and management, the quality of disclosure varies and many companies do not report at all. Initiatives, such as the Carbon Disclosure Project, seek to increase the level of voluntary disclosure, by communicating to companies the importance of this information to investors and providing guidance about what should be disclosed.

Appendix: Methodology Notes

Most infrastructure projects have long useful lives, so a long-term valuation approach is required to capture the range of factors that can impact on value across the life of the project. In addition, the financing of the project is often complex, with multiple layers of secured debt, unsecured debt, and equity securities; such that the specific risk associated with the particular capital structure should be taken into account.

As such it is generally accepted that the projects should be valued using a long-term discounted cash flow (DCF) analysis on the project cash flows available to equity investors. The discount rate should be set having regard to the sector and the market in general and to account for any risks specific to the project being evaluated that are not captured in the cash flow forecasts. Where possible, it is generally considered preferable to adjust the cash flows (rather than the discount rate) to take account of specific risks. For the climate change scenarios presented in this paper, the cash flows were adjusted rather than the discount rate.

The term of a utility project depends on the nature of the asset in question:

- For power generation assets, most plants have a specific useful life and are valued to maturity.
- Many network assets are held in either freehold/ perpetuity or subject to a long-term lease. Such assets are appropriately modelled by forecasting cash flows for 10-20 years and applying a terminal value.

To determine the sensitivities for the electricity and gas distribution and transmission network assets, the key variable is the expected growth (or decline) in capital expenditure required to maintain or improve the networks. For simplicity, it is assumed that variations in peak demand translate to the same proportional increase in capital expenditure requirements. It should be noted that, in practice, most network capacity increases occur in a step-wise fashion and at specific points in networks.

The impact on equity returns is assessed against the funding of these requirements over the 10-20 year period of the model and an assumed exit at a multiple of the regulated asset base. In terms of key valuation metrics, rather than the EBITDA multiple, the preferred measurement technique is a multiple of the regulated asset base.

Whilst the cash yield to equity investors generated by the network assets is a key consideration in the listed market, this factor is not a key focus of the analysis. However, it would be expected that, all other factors being equal, that increased capital expenditure requirements may initially have a detrimental impact on cash flows (due to the need to retain additional cash flow or raise debt to fund expenditure). In subsequent years, distributions to equity would be expected to increase as the investors would expect to earn greater cash flows off the (now increased) regulatory asset base.

Key Risks to Analysis

Results are sensitive to the carbon price assumptions. The carbon prices modelled are all based on prices in currently operating carbon markets.

Future carbon prices are highly uncertain, especially in the absence of specific regulatory proposals. Forecasts of future carbon prices vary significantly depending on the assumptions adopted. Recent attempts to model carbon price outcomes resulted in estimates of:

- \$186 per tCO_2-e in 2050 – Allen Consulting Group modelling of an ‘early action’ scenario to reduce greenhouse gas emissions by 60% from year 2000 levels by 2050.[xxxv]
- \$77 to \$525 (2005 A\$) per tCO_2-e in 2050 – ABARE modelling across a range of scenarios to reduce global CO_2 emissions by 40% by 2100 relative to the reference case.[xxxvi]

These variations result in part from different reduction targets contemplated, but also reflect the uncertainty about how costly it will be to achieve the targeted greenhouse gas reductions.

The modelling in this report also treats the carbon price as independent of other aspects of the carbon pricing regime such as sector coverage and the emissions ‘cap’ (or reduction target). However, in practice, carbon prices are determined by supply and demand for tradeable permits and demand is strongly affected by a range of factors including sector coverage and the emissions cap.

References

[i]Australian Bureau of Agricultural and Resource Economics (2006) *Economic Impact of Climate Change Policy: The Role of Technology and Economic Instruments,* p22, available from www.abareconomics.com/publications_html/climate/climate_06/cc_policy_nu.pdf.

[ii]Ibid.

[iii]Department of Environment and Heritage (2006) *AGO Factors and Methods Workbook,* p39 available at http://www.greenhouse.gov.au/workbook/pubs/workbook2006.pdf.

[iv]Environment Australia (1999) *Emission Estimation Technique Manual for Gas Supply,* available at http://www.npi.gov.au/handbooks/approved_handbooks/pubs/fgassup.pdf

[v]Includes all regulated assets, both publicly and privately held.

[vi]SP Ausnet (2006) Half Year Results Presentation, p22.

[vii]AMP Capital (2005) *Emissions Trading Permit Allocation and Investment in the Australian Electricity Generation Sector* available at http://www.ampcapital.com.au/corporatecentre/research/sriresearch.asp.

[viii]CCGT or Combined Cycle Gas Turbine technology involves recovery of waste gases for use in supplementary steam generation, thereby increasing efficiency compared to gas combustion alone.

[ix]Numerous publications have discussed this issue. For a thorough treatment, including estimation of the size of windfall profits, see IPA Energy (2005) *Implications of the EU Emissions Trading Scheme for the UK Power Generation Sector (Report to UK Department of Trade and Industry)* available from http://www.ipaenergy.co.uk/downloads&publications/FINAL%20Report%201867%2011-11-05.pdf.

[x]Relevant factors include market demand (which is influenced by weather patterns), interconnection of electricity networks, network capacity, regulation and environmental approvals, fuel prices and proximity to fuel sources.

[xi]CCGT is assumed to be the last entrant generator.

[xii]CCGT is assumed to be the last entrant generator.

[xiii]CCGT is assumed to be the last entrant generator.

[xiv]Such as established by the Mandatory Renewable Energy Target (MRET). For further information see www.orer.gov.au.

[xv]Australian Bureau of Agricultural and Resource Economics (2005) *Australian Energy – National and State Projections to 2029/30*, p26, available at http://abareonlineshop.com/product.asp?prodid=13272.

[xvi]See *Climate Change and Infrastructure – Planning Ahead* at www.greenhouse.vic.gov.au.

[xvii]Australian Bureau of Agricultural and Resource Economics (2006) *Economic Impact of Climate Change Policy: The Role of Technology and Economic Instruments,* p30, available from www.abareconomics.com/publications_html/climate/climate_06/cc_policy_nu.pdf.

[xviii]Thomas, M. (2002) *Energy and Energy Intensive Industry. Proceedings: Living with Climate Change Conference,* quoted in Australian Greenhouse Office (2003) *Climate Change: An Australian Guide to the Science and Potential Impacts,* p138, available from http://www.greenhouse.gov.au/science/guide/.

[xix]Australian Bureau of Agricultural and Resource Economics (2005) *Australian Energy – National and State Projections to 2029/30*, p26, available at http://abareonlineshop.com/product.asp?prodid=13272.

[xx]Change in electricity demand from climate change based on Australian Bureau of Agricultural and Resource Economics (2006) *Economic Impacts of Climate Change Policy: The Role of Technology and Economic Instruments,* base case discussed on p18 and climate change case on p50 available at http://abarepublications.com/product.asp?prodid=13454.

[xxi]Hastings estimate of change due to increased use of air-conditioners.

[xxii]Based on Thomas, M. (2002) *Energy and Energy Intensive Industry. Proceedings: Living With Climate Change Conference,* quoted in Australian Greenhouse Office (2003) *Climate Change: An Australian Guide to the Science and Potential Impacts,* p138, available from http://www.greenhouse.gov.au/science/guide/

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[xxiii]Change in gas demand from climate change based on Australian Bureau of Agricultural and Resource Economics (2006) *Economic Impacts of Climate Change Policy: The Role of Technology and Economic Instruments,* Based case discussed on p18 and climate change case on p50 available at http://abarepublications.com/product.asp?prodid=13454.

[xxiv]This assumption is predicated on the relationship between weather and residential gas demand, with warmer weather reducing the heating demand for gas in Australia's southern states

[xxv]Prime Minister of Australia John Howard, 'Address to the Liberal Party Federal Council' (speech delivered in Sydney, 3 June 2007) available from http://www.pm.gov.au/media/Speech/2007/Speech24350.cfm .

[xxvi]Commonwealth Scientific and Industrial Research Organisation (CSIRO) 2006 *Climate Change Scenarios for Initial Assessment of Risk in Accordance with Risk Management Guidance* www.greenhouse.gov.au.

[xxvii]Based on Australian Bureau of Agricultural and Resource Economics (2005) *New Energy Technologies in APEC*, pp 38 and 186, available from www.ewg.apec.org.

[xxviii]Calculated from Electricity Supply Association, *Electricity and Gas Australia 2006*, pp51-60, and other sources, including http://www.energy.qld.gov.au/low_emissions_technology.cfm.

[xxix]Ibid, p34. Classification as subcritical, supercritical or ultra supercritical depends on the temperature and pressure of the steam used to drive the turbine and produce electricity.

[xxx]Ibid, p181.

[xxxi]For further information see http://www.greenhouse.gov.au/ges/index.html.

[xxxii]Australian Bureau of Agricultural and Resource Economics (2005) *New Energy Technologies in APEC*, p184, available from www.ewg.apec.org.

[xxxiii]Ibid, p180.

[xxxiv]See for example, CS Energy 'Kogan Creek Power Station Project Commences' (Media Release, 20 May 2004) available from http://www.csenergy.com.au/media_centre/documents/040520announcementwebversion_000.pdf.

[xxxv]Allen Consulting Group (2006) *Deep Cuts in Greenhouse Gas Emissions: Economic, Social and Environmental Impacts for Australia*, p30, available from www.acfonline.org.au/uploads/res_BLRT_allensreport.pdf.

[xxxvi] Australian Bureau of Agricultural and Resource Economics (2006) *Economic Impacts of Climate Change Policy: The Role of Technology and Economic Instruments,* p4, available from http://abarepublications.com/product.asp?prodid=13454.

Resources

Climate Science

Intergovernmental Panel on Climate Change http://www.ipcc.ch/

- *Fourth Assessment Report – Climate Change 2007*

Australian Greenhouse Office www.greenhouse.gov.au:

- *Stronger Evidence but New Challenges: Climate Change Science 2001-2005*

Australia's Greenhouse Gas Emissions

National Greenhouse Gas Inventory http://www.greenhouse.gov.au/inventory/index.html

Energy and Greenhouse Projections

National Greenhouse Gas Projections
http://www.greenhouse.gov.au/projections/index.html

International Energy Agency www.iea.org:

- *World Energy Outlook www.worldenergyoutlook.org*

Australian Bureau of Agricultural and Resource Economics www.abare.gov.au:

- *Australian Energy: National and State Projections to 2029-2030*
- *Economic Impact of Climate Change Policy: the Role of Technology and Economic Instruments*

Projected Impacts for Australia

Australian Greenhouse Office www.greenhouse.gov.au:

- *Climate Change – An Australian Guide to the Science and Potential Impacts*
- *Climate Change Scenarios for Initial Assessment of Risk in Accordance with Risk Management Guidance*

Commonwealth Scientific and Industrial Research Organisation www.csiro.au:

- *Climate Change Projections for Australia http://www.dar.csiro.au/impacts/future.html*

International Agreements on Climate Change

United Nations Framework Convention on Climate Change and the Kyoto Protocol www.unfccc.int

Asia-Pacific Partnership on Clean Development (AP6) www.dfat.gov.au/environment/climate/ap6/

Greenhouse Accounting

World Resources Institute and World Business Council for Sustainable Development:

- *The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard www.ghgprotocol.org*

Carbon Trading

European Union Greenhouse Gas Emissions Trading Scheme http://ec.europa.eu/environment/climat/emission.htm

Chicago Climate Exchange www.chicagoclimatex.com

New South Wales Greenhouse Gas Abatement Scheme www.greenhousegas.nsw.gov.au

The World Bank Carbon Finance Unit www.carbonfinance.org:

- *State and Trends of the Carbon Market 2006*

International Emissions Trading Association www.ieta.org
Australian Financial Markets Association www.afma.com.au:

- *Market Data and Research – Environmental Products*

Australasian Emissions Trading Forum *www.aetf.net.au*

Climate Change and Investment

Institutional Investors Group on Climate Change (UK) www.iigcc.org

Investor Network on Climate Risk www.incr.com

Investor Group on Climate Change (Australia/New Zealand) www.igcc.org.au

The Carbon Disclosure Project www.cdproject.net

The Carbon Trust www.carbontrust.co.uk:

Resources

Valuing Climate Change Risk

The Carbon Trust www.carbontrust.co.uk:

- *Climate Change and Shareholder Value*
- *A Climate for Change – A trustee's guide to understanding and addressing climate risk*
- *Brand Value at Risk from Climate Change*
- *Investor Guide to Climate Change*

United Nations Environment Programme Finance Initiative www.unepfi.org:

- *Show Me The Money: Linking Environmental, Social and Governance Issues to Company Value*
- *The Materiality of Social, Environmental and Corporate Governance Issues to Equity Pricing*

Enhanced Analytics Initiative www.enhancedanalytics.com

Ceres www.ceres.org and World Resources Institute www.wri.org:

- *Framing Climate Change Risk in Portfolio Management*

Total Environment Centre www.tec.org.au (authors AMP Capital Investors and Baker & McKenzie):

- *Climate Change and Company Value: a Guide for Company Analysts*

Climate Change and Electricity and Gas Infrastructure

International Energy Agency www.iea.org:

- *Emissions Trading and its Possible Impacts on Investment Decisions in the Power Sector*

Australian Bureau of Agricultural and Resource Economics www.abare.gov.au:

- *New Energy Technologies: Measuring Potential Impacts in APEC*

AMP Capital www.ampcapital.com.au:

- *Emissions Trading Permit Allocation and Investment in the Australian Electricity Generation Sector*

National Energy Market Management Company www.nemmco.com.au:

- *Impact of Greenhouse Policies on Electricity Demands (author: National Institute of Economic and Industry Research)*

Department of Trade and Industry (UK) www.dti.gov.uk:

- *Implications of the EU Emissions Trading Scheme for the UK Power Generation Sector (author: IPA Energy Consulting) available from www.ipaenergy.co.uk*

Investor Group on Climate Change (IGCC)

The IGCC represents institutional investors, with total funds under management of over $375 billion, and others in the investment community interested in the impact of climate change on investments. The aim of the IGCC is to ensure that the risks and opportunities associated with climate change are incorporated into investment decisions for the ultimate benefit of individual investors. One of the key ways in which IGCC can work toward achieving this aim is through involvement in research projects such as this, to help the investment community better understand and assess climate change impacts.

Monash Sustainability Enterprises (MSE)

MSE is a multi-disciplinary research centre which specialises in the development of robust methodologies to analyse linkages between corporate social and environmental management and financial drivers. MSE has pioneered the practical application of environmental and social rating and analysis in Australian financial markets. Through its relationship with Regnan governance research and engagement services, MSE is the leading ESG research provider to many of Australia's largest institutional investors.

Hastings Funds Management

Hastings currently manages nine infrastructure funds, four of which are listed on the Australian Stock Exchange (ASX) and five unlisted wholesale funds investing in infrastructure equity and high yield debt. Hastings also manages two private equity funds and one timber investment vehicle. The Hastings team has the expertise required to invest in, and manage, infrastructure and privatisation investments encompassing project finance, regulation, banking, tax, risk management and an understanding of the infrastructure sector's value drivers.

Australian Government

The Australian Government Department of the Environment and Water Resources (formerly the Department of the Environment and Heritage) develops and implements national policy, programs and legislation to protect and conserve Australia's natural environment and cultural heritage.

Other reports in the series are available at www.igcc.org.au