Energy security and the introduction of GHG emissions pricing

Transitional issues in the electricity sector around the introduction of a price on GHG emissions

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ACIL Tasman
Economics Policy Strategy

ACIL Tasman Pty Ltd

ABN 68 102 652 148
Internet www.aciltasman.com.au

Melbourne (Head Office)
Level 4, 114 William Street
Melbourne VIC 3000

Telephone (+61 3) 9604 4400
Facsimile (+61 3) 9604 4455
Email melbourne@aciltasman.com.au

Brisbane
Level 15, 127 Creek Street
Brisbane QLD 4000
GPO Box 32
Brisbane QLD 4001

Telephone (+61 7) 3009 8700
Facsimile (+61 7) 3009 8799
Email brisbane@aciltasman.com.au

Canberra
Level 1, 33 Ainslie Place
Canberra City ACT 2600
GPO Box 1322
Canberra ACT 2601

Telephone (+61 2) 6103 8200
Facsimile (+61 2) 6103 8233
Email canberra@aciltasman.com.au

Darwin
GPO Box 908
Darwin NT 0801

Email darwin@aciltasman.com.au

Perth
Centa Building C2, 118 Railway Street
West Perth WA 6005

Telephone (+61 8) 9449 9600
Facsimile (+61 8) 9322 3955
Email perth@aciltasman.com.au

Sydney
PO Box 1554
Double Bay NSW 1360

Telephone (+61 2) 9389 7842
Facsimile (+61 2) 8080 8142
Email sydney@aciltasman.com.au

For information on this paper

Please contact:

Paul Hyslop
Telephone 07 3009 8700
Mobile 0417 392 079
Email p.hyslop@aciltasman.com.au

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Introduction

This paper aims to discuss the main risks to energy security (electricity) with the introduction of greenhouse gas (GHG) emissions pricing.

The paper considers electricity sector GHG emissions in the context of total Australian GHG emissions. This leads to an assessment of the role that electricity will be expected to play in abating GHG emissions in the first years after its introduction (to 2020).

This role is then considered in terms of the change that it is expected to bring within the electricity sector. As electricity is a central part of our everyday lives, forced rapid change is not without risks with respect to security of supply. The major security of supply risks associated with the change are considered.

Next the paper canvasses the issue of compensation for the electricity sector both from an efficiency and equity perspective. The recent history of coal fired transactions and investments is used to assess whether it is reasonable to assume investors should have been aware of the likelihood of the introduction of GHG emissions pricing.

Finally the potential impact on wholesale and retail electricity prices is considered.

Emission trends and abatement trajectories

As a nation Australia is estimated to emit between 1.25% and 1.5% of the worlds anthropogenic GHG emissions measured in terms of carbon dioxide equivalence (CO_2-e). Reporting of GHG emissions is done under two different accounting methodologies. The United Nations Framework Convention on Climate Change (UNFCCC) GHG emissions accounting methodology stems from the Convention that was signed in 1992 and ratified in the middle of the 1990s. The Kyoto Protocol's GHG emissions accounting methodology applies specifically to the targets set under the Kyoto Protocol and differs from the UNFCCC methodology. Specifically the methodologies differ with respect to the treatment of Land Use, Land-Use Change and Forestry (LULUCF). The Kyoto accounting methodology allows 131.5 Mt of GHG emissions for LULUCF in the 1990 base year whereas the UNFCCC accounting only allows 46.1 Mt of GHG emissions, a difference of 85.4 Mt.

In 2008 the world is estimated to have emitted in the vicinity of 43,000 Mt of GHG of which around 70% or 30,000 Mt was associated with fuel combustion[1]. In 2008, Australia (using the UNFCCC methodology) reported that it emitted a total of 549.5 Mt of GHG emissions excluding (LULUCF) and 618 Mt of GHG including LULUCF. This was against the base year of 1990 where Australia reported emitting 418.3 Mt of GHG without LULUCF and 464.5 Mt of GHG with LULUCF. Emissions growth under the UNFCCC accounting methodology between 1990 and 2008 is 31.4% without LULUCF and 46.4% with LULUCF.

1 World Bank GHG emissions statistics provided at http://data.worldbank.org/topic/environment

As Australia has ratified the Kyoto Protocol it is required to limit GHG emissions to 108% on average of 1990 levels over the initial commitment period between 2008 and 2012 using the Kyoto GHG emissions accounting methodology. As noted above, the Kyoto GHG emissions accounting differs from the UNFCCC accounting. Under Kyoto GHG emissions accounting Australia's GHG emissions in the base year of 1990 are set at 550 Mt. The 2008-2012 target is 108% of the 1990 base year, which is 594 Mt. Australia's 2008 GHG emissions under Kyoto accounting have been reported as 576 Mt[2]. Australia is projecting that average Kyoto accounted GHG emissions over the period 2008 to 2012 will be capped at 106% of 1990 levels or 584 Mt. The rest of the discussion in this section is based on the Kyoto GHG emissions accounting.

In 2010, the Australian Government projected that Australian GHG emissions (under the Kyoto accounting framework) would increase by a further 113 Mt or 24% to 690 Mt in 2020 (refer Figure 1), in the absence of further policy action. Growth in GHG emissions between 2010 and 2020 under the no further policy action framework (refer Figure 2) is expected to be driven primarily by export oriented industries although transport and agriculture also show significant increases.

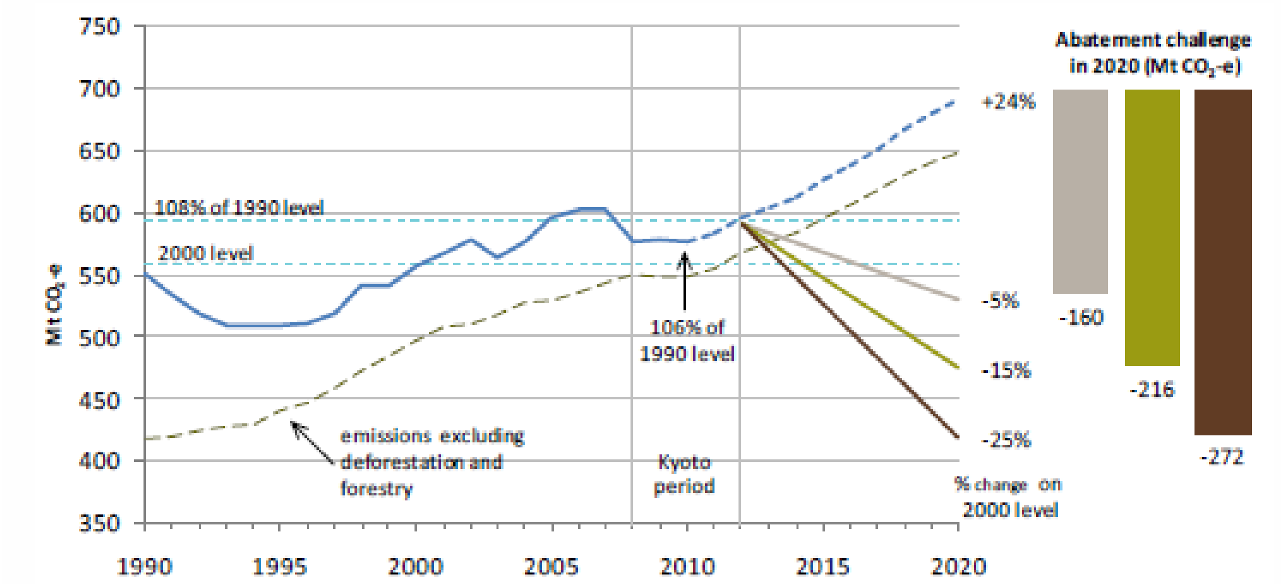
Figure 1 also shows illustrative abatement trajectories to achieve 5%, 15% and 25% reductions in GHG emissions over 2000 levels by 2020 (Kyoto accounting) requiring GHG emissions reductions of 160 Mt, 216 Mt and 272 Mt respectively compared with the no further policy action projection of 690 Mt in 2020.

Responding to the threat of climate change caused by anthropogenic GHG emissions has bipartisan political support at the national level. Even though the major parties differ with respect to policies to achieve GHG emissions reductions, the aims are almost identical seeking to achieve a 5% reduction over 2000 levels or 160 Mt of abatement over the no further policy action projection.

However if relying on an emissions price to drive abatement (as the Government has outlined), meeting the target will involve a combination of domestic abatement and the purchase of permits from the international market (international permits would be expected to be purchased where they have a lower cost than marginal domestic abatement). The Opposition's proposed 'direct action' program appears to rely on making a market in abatement with the Government as the buyer and it is not clear whether it will rely on purchasing international permits as a backstop.

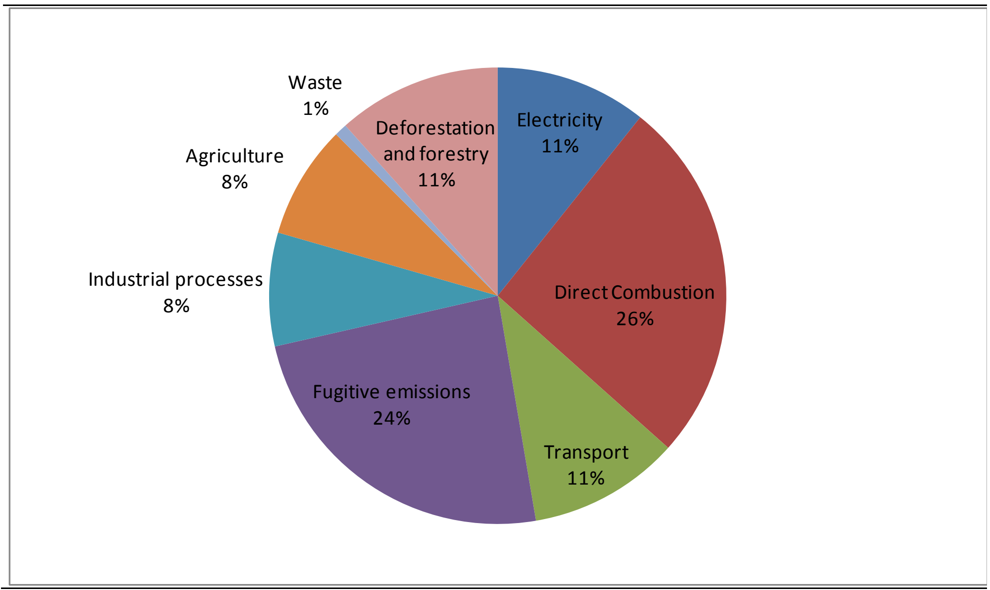
[2] Department of Climate Change and Energy efficiency at http://www.ageis.greenhouse.gov.au/NGGI.aspx

Figure 1 **Emissions trends, Australia – 1990 to 2020**



Note: Abatement trajectories are illustrative commencing in 2011-12 assuming a start point of 108% of 1990 levels and proceed along a straight line to the target
Data source: Australian Government, 2011, ―Australia's Emissions Projections 2010, Department of Climate Change and Energy Efficiency; page 8.

Figure 2 **GHG emissions growth by sector – Kyoto accounting (1990 to 2008-12)**



Data source: Australian Government, 2011, ―Australia's Emissions Projections 2010, Department of Climate Change and Energy Efficiency; page 5.

In terms of the total of 576 Mt of GHG emissions reported in 2008:

- Energy constitutes around 72% of all GHG emissions with fuel combustion about 90% of all energy and 65% of all GHG emissions.
  - Stationary energy makes up nearly 80% of all fuel combustion and around 50% of all GHG emissions with transport making up the remaining fuel combustion GHG emissions.
    - … Electricity and heat production makes up around 70% of all stationary energy GHG emissions and around 35% of all GHG emissions.

Low hanging fruit

The optimal approach to abating GHG emissions is to source abatement at the lowest possible cost. While there is undoubtedly opportunities to find some 'low hanging fruit" across all sectors of the economy, electricity is expected to provide a significant amount of low cost abatement. This is because electricity represents the biggest single component of GHG emissions and there is significant potential for abatement through fuel switching from coal to gas using existing proven technologies. In the long term there are a number of potential low or zero emissions technologies capable of producing reliable base load supply that would allow even greater abatement (e.g. nuclear fusion, geothermal, solar thermal, tidal, carbon capture and storage, etc.). However these technologies may take many years to be both technically and/or commercially viable. Therefore gas, generating electricity in combined cycle gas turbines, while still a GHG emitting technology, is expected to be a key transition fuel for the Australian electricity industry as it moves to a lower GHG emissions future.

Regardless of whether it is through a carbon pricing regime, or through direct action to reduce emissions, the electricity sector is expected to be called upon to deliver large volumes of abatement to 2020, through the closure of GHG emissions intense coal fired stations and replacing them with less GHG emissions intense gas fired power stations. Indicatively, replacing 1000 MW of brown coal fired generation with 1000 MW of combined cycle gas turbine generation (CCGT) would reduce emissions by around 7 Mt per annum. Similarly for 1000 MW of black coal plant replaced by 1000 MW of CCGT the savings would be in the order of 4 Mt per annum.

ACIL Tasman modelling of the national electricity market (NEM) when using a carbon pricing policy (tax or emissions trading) to drive GHG emissions abatement provides an indication of the amount of abatement likely from the electricity sector. Using the Commonwealth Treasury CPRS-5[3] carbon price projection and comparing it with the no further policy action case indicates that NEM based GHG emissions would fall from around 210 Mt to around 164 Mt, or 56 Mt abatement over no further policy action. Western Australia (WA) would be expected to contribute around 5 Mt by 2020. The combined savings of 61 Mt is 38% of the 160 Mt total abatement that Australian Government has projected would be required to meet the 5% GHG emissions reduction target in 2020.

3 The CPRS-5 carbon price projection is for the case in which 2020 GHG emissions target is 5% below the 2000 level emissions.

Regardless of whether the emissions are driven by putting a price on GHG emissions or through direct action, further reductions in GHG emissions of around 60 Mt per annum by 2020 would be expected from the electricity sector. ACIL Tasman estimates that under a carbon tax or emissions trading (ETS) around 20% of this abatement would be derived from lower demand for electricity (price elasticity effects of higher electricity prices) with the remainder from fuel substitution of coal with gas.

Western Australia – a special case

Achieving large scale emission reduction in the WA WEM is not as easily achieved due to the structure of the wholesale market, the presence of higher gas prices and no CO_2-e intensive brown coal plant. As generators are paid a fixed capacity payment per MW of capacity available to the market, it is unlikely that incumbent coal-fired generators would shutdown on a commercial basis between 2011 and 2020. This is because even though a coal-fired station may make little or no money from the energy market, its capacity payment from being available (typically over $150,000/MW/year) significantly exceeds the plants annualised fixed O&M costs (typically $50,000-$60,000/MW/year).

As gas in WA is largely supplied over the Dampier to Bunbury pipeline, there are strategic fuel diversity benefits in maintaining some coal plant which are based around Collie in the south-west of WA.

Any abatement would be expected to come from fuel switching, particularly with respect to future investments required to meet demand growth. This is because while the capacity payments are enough to keep existing coal fired plant solvent, they would not be enough to fund new coal plant. In the case of incumbent generation fuel switching would only occur where the GHG emissions price forced the marginal cost of incumbent coal plant above that of gas fired plant. A number of gas fired plant have relatively low priced legacy gas contracts in WA, but these are all likely to be replaced with higher priced contracts over the next few years. Hence there appears to be limited scope to reduce emissions from existing high intensity emitters in WA.

ACIL Tasman modelling of the WA WEM indicates abatement of around 5 Mt through in 2020 compared with the no further policy action case which is mostly through new entrants required to meet demand growth being gas fired rather than coal fired.

Unprecedented change

The scale of the investment needed and the rapid shift in technology deployed and the type of fuel that will be used is unprecedented in the history of the development of the electricity sector in Australia. The closest parallel might be the post second world war era in which rapid electrification occurred across Australia. However even the resources that went into that period of expansion cannot be truly compared to that which is expected to occur over the next decade because of the speed at which it is expected to take place and the deep reliance of the Australian economy and individuals on the reliable supply of electrical energy.

In order for the fuel substitution to be able to occur, ACIL Tasman estimates that investments of around 8,500 MW of CCGT and open cycle gas turbines (OCGT) will be required (6,300 MW of CCGT and 2,200 MW of OCGT). In 2011 prices this is around $10.5 billion dollars of investment in new gas fired generation plant. This is in addition to the expected investment of around $20 billion in renewable energy under the expanded renewable energy target. This does not include new investments in gas pipelines or in electrical transmission systems which are already under stress in places from renewable energy investments. Most renewable energy investments are wind farms and the stresses are caused by the remote location of some of the investments and the uncertain and intermittent nature of the output.

Coupled with the investment in gas fired generation, ACIL Tasman modelling also indicates that around 4,700 MW of generation capacity will be forced to retire by 2020 (around 10% of current installed capacity) on the basis of being unable to fund its avoidable costs. ACIL Tasman also estimates that coal fired power station operating cash flow or EBITDA which funds debt and equity capital would be around $11 billion less (in 2011 dollars) compared with the no further policy action case between 2011 and 2020 under a emissions pricing regime based on CPRS-5.

In the event that a steeper GHG emissions abatement trajectory was pursued, say 15% or 25% below 2000 levels by 2020, the GHG emissions price path would be higher, the amount of plant expected to close by 2020 would be greater and significantly larger amounts of replacement plant would be required. It is also notable that for steeper GHG emissions abatement trajectories, that gas fired plant are likely to play a lesser role in transition as investments over the cycle may not be able to achieve required returns. This is because while gas fired plant are less intense in terms of GHG emissions than coal plant, they still emit significant quantities of GHG[4] and at some point, as the trajectory deepens, they will also not be viable.

Energy security

There are a number of issues that may affect energy security during the period of transition, particularly over the period to 2020. These include:

- Reserve margins being threatened by coal plant closing without enough replacement plant being brought online
- Maintenance being reduced or even stopped on financially distressed plant leading to a fall in reliability
- Disruption to plant financing leading to management uncertainty and poor maintenance and operation
- Loss of skills and expertise required to operate and maintain plant that are likely to close.

4 A 1000 MW CCGT producing at 85% capacity factor (base load) would be expected to produce around 3 million tonnes of CO_2-e per annum.

Reserve margins threatened

The amount of plant that is expected to be retired and replaced means that it is conceivable that retirements could occur without replacement. Ideally plant retirements would occur with reasonable periods of warning such that replacement plant could be planned and constructed. Planning and construction of CCGT would typically take five years which allows 2 to 2 ½ years of planning and permitting and 2 ½ to 3 years construction.

Existing plant under threat of closure would be expected to seek to continue to operate until they could not meet there avoidable costs even though returns to capital may fall dramatically. However, in practice this is a very difficult matter to predict in advance, because of the volatile and uncertain nature of the earnings in electricity markets. It is possible to hedge the uncertainty in forward markets but companies under threat of closure would be expected to have difficulty writing such forward agreements because of their poor credit quality and probability of failing financially and hence not existing to meet obligations under the hedging arrangements. This means that electricity company boards of directors would be faced with a difficult set of competing requirements in:

- Not announcing closures too early as doing so will likely damage any remaining capital value in the plant
- Not announcing closures too late and facing the prospect of trading while insolvent.

These competing requirements suggest that individual companies owning generating plant at risk are likely to hold off announcing any plant closures until it is clearly no longer avoidable and then close the plant quickly to avoid the risk of trading while insolvent which would be unlikely to provide the advance warning required for a seamless transition.

There is a notable exception to this situation, being the case where the owner of the plant at risk of closing is also a potential investor in the replacement plant. In this case the closure and new investment risks could be internalised. This obviously depends on the willingness of these owners to make new investments when faced with losses on existing investments as a consequence of policies to curb GHG emissions.

Reduced maintenance

Plant that are under increasing financial stress are likely to seek to minimise operating expenditure and delay any capital expenditure on maintenance. This may be the case even where the plant is not at imminent risk of having to close. Many generation plant are reasonably heavily geared with debt. Equity owners and managers of plant under threat of closure could seek to squeeze out every last drop of return in the short term by deferring maintenance activities that would affect the plants reliability in the medium term. This could have consequential impacts on both the power systems ability to meet demand reliably and the price volatility.

Disruption to plant financing

The traditionally heavy gearing of coal fired generators and the use of project financing, at least in the case of private operators, creates some issues with the advent of GHG emissions pricing. Many of the project financings were put in place before the substantial change of policy by the Australian Government to embrace GHG emissions pricing in June 2007. The introduction of GHG emissions pricing, even at relatively modest prices of $20/tonne of CO_2-e, is likely to lead to some asset equity owners defaulting and handing the assets over to project financiers.

Project financiers usually consist of bank syndicates that then sell down the debt to other institutions and investors. While the project financing banks usually carry out sufficient due diligence prior to commitment, they have little practical knowledge or experience in terms of managing and operating power stations. Handing the responsibility for the asset to the project financiers is not optimal in the context of minimising disruption to energy security.

Faced with a defaulting asset, bank syndicates will tend to focus on recovering as much if not all of the debt investment possible. While ideally the bank syndicate would sell the asset to a new equity investor at a lower capital value, buyers may be difficult to find and the insolvency process may take some time to resolve. Simply coordinating syndicates that may have 30 or more debt holders may take considerable time and effort. As an example, the recent Alinta Energy difficulties have taken at least 12 months to resolve.

In the interim, the bank syndicate may seek an arrangement with the existing management/owners to continue to operate and manage the asset. However having effectively written off equity and without significant incentive, existing management/owners may quickly lose interest in making the difficult decisions to keep the plant operational.

Any period of insolvency or threatened insolvency is highly disruptive as decision making tends to be short term focussed. This could include cutting maintenance expenditure and would undoubtedly mean no expenditure where returns were likely to accrue over longer time frames.

Such an environment is unlikely to lead to sound long term decision making which is ultimately required to provide electricity reliably and cost effectively.

Skills and expertise

Generation plant, particularly coal fired plant, require a highly skilled and stable workforce to be operated and maintained reliably. These workforces are already in demand from other industries in the current boom cycle, particularly the mining industry. Ideally the workforce of each generation plant under threat of closure would remain in place until the plant closure timetable was confirmed, with the workforce then wound down in a gradual and planned manner as the closure proceeded.

In practice, employees concerned about their futures are unlikely to identify the option of remaining with their current employer as their number one career option. In order to encourage them to stay, employers would need to provide information about the likely closure well in advance and pay handsomely to reward employees for staying. However, as discussed above, owners of generation plant have incentives to avoid early announcements of likely closures and under financial stress may not have the resources to reward employees for remaining loyal.

The loss of key skilled employees could be very disruptive both in terms of the operation and maintenance of coal fired generation plant. Critical institutional knowledge and experience would be expected to be lost that would at best lead to an increase in the cost of maintenance and in the worst case lead to deleterious impacts on plant operation and reliability.

This situation would be made worse where new investors seeking to establish workforces to operate replacement plant look to key skilled employees within existing plant under threat of closure. It is not unusual to establish the workforce 12 months prior to plant commissioning to train them on the operation and maintenance of the new plant and to establish operating and maintenance procedures.

Notably, where the owner of the plant at risk of closing is also a potential investor in the replacement plant these risks could be internalised. Again this obviously depends on the willingness of these owners to make new investments when faced with losses on existing investments as a consequence of policies to curb GHG emissions.

The question of compensation

One of the most vexed questions faced by both government and the industry is whether or not power stations and industry that are major emitters of GHG and export orientated industry that are major users should be provided with compensation following the introduction of GHG emissions pricing. There are three main considerations with respect to the issue of compensation being:

- The continued effective and efficient operation of electricity markets
- The potential loss of exporting industries to competitors that are unlikely to face GHG emissions costs (particularly developing countries that are not currently committed to targets)
- Equity issues where changes to government policy have damaged bona fide investments in electricity generation and industry which are significant electricity users

Effective and efficient operation of electricity markets

A number of issues have been raised with respect to energy security which have the potential to disrupt electricity markets, create inefficient and volatile pricing and undermine reliability of supply. The underlying factor relates to the step change in input costs for most major participants as a consequence of GHG emissions pricing and the question whether markets will continue to operate efficiently in the transition years following this step change. Issues that may cause problems include:

- The potential for reserve margins to be threatened because markets fail to provide signals for replacement plant far enough in advance as existing plant are closed in response to GHG emissions pricing.
- Incentives to reduce maintenance in order to harvest short term benefits which reduce power supply reliability
- Poor management and decision making following disruption to plant financings
- Retention of critical skills and experience bases.

While compensation would not necessarily overcome any of these issues in isolation, it could be used to provide incentives to overcome them. As examples, compensation could:

- include conditions that required management and financiers to work together to avoid structural insolvency where the underlying asset is capable of meeting its avoidable costs and hence remains operationally viable
- include conditions for plant to provide adequate warning of retirement
- provide the necessary financial resources to retain key staff
- mitigate sovereign risk concerns and encourage investment in replacement plant (without mandating it) which has the added benefit of internalising many of the co-ordination issues which could put the reliability of supply at risk.

While ultimately government must make the decision as to whether compensation is warranted to support the ongoing effective and efficient operation of electricity markets, in doing so they must be cognisant of the central role that electricity plays in the everyday lives of all Australians and the potential disruption to those everyday lives if electricity supplies are subject to increased price volatility and in the worst case disrupted. In this sense targeted compensation could be effected as a form of insurance policy during the inevitable transition away from coal fired power stations.

Investing, constructing and operating large scale power stations requires a number of specialised skills which are not easily acquired. Many of the companies with the specialised skills that Australia will look to in order to provide the new investment will be the same companies faced with reduced cash flows and in some cases early retirements which they would argue were not foreseen at the time of the investment.

Export orientated industries

It should be noted that the provision of stable and low cost energy supplies has provided one of the cornerstones for Australia's ability to be able to compete in key international markets. The imposition of GHG emissions pricing will impose significant additional costs on some key export industries, with others that are large electricity users facing significant increased cost in relation to electricity purchases.

In an environment in which all major GHG emitting nations reached agreement to limit emissions and effectively pay a global GHG emissions price, Australia's key competitors would face similar cost increases and be forced to make similar adjustments to processes and facilities to manage these increases. However, in the situation in which Australia, accepts a price on GHG emissions but key competitors do not, the longstanding comparative advantage in which energy prices have played a key role, will be eroded.

Equity considerations

In considering whether there are equity grounds for providing compensation, it is relevant to look at the recent history of coal fired power station transactions and investments in order determine whether GHG emissions pricing was factored in, and if not factored in, whether it was reasonable or reckless to do so.

Table 1 sets out some recent coal fired power station transactions. The transaction prices were compared with the asset fair value range based on expected discounted cash flows using electricity market projections without GHG emissions pricing. In every case it is concluded that the asset valuation did not appear to include any discounting for the possible introduction of GHG emission pricing.

Table 1 **Some recent coal fired transactions**

Date	Transaction	Implied value/MW	Emissions pricing included
Mar 07	4.71% of Loy Yang A	$2.12 million	No
Jul 06	9.3% of Loy Yang	$2.05 million	No
Jun 06	NRG Flinders/Osborne [a]	$0.75 million	No
Dec 04	Loy Yang B (part of EME international transaction) [b]	~$1.80 million	No
Jul 03	Loy Yang A	$2.12 million	No
Jun 03	50% of Redbank power station [c]	$3.16 million	No
Aug 02	50% of Tarong North power station	$1.65 million	No

[a] artificially depressed because of significant liabilities on Osborne Cogeneration power purchase agreement

[b]. artificially low because of hedge with State of Victoria at below market rates

[c]. artificially high because electricity sold covered by hedge agreement at above market rates

Note: Assessment of whether emissions pricing was included in transaction price is based on assessed fair value range with emissions pricing excluded

Data source: Grant Samuel Independent Expert's Report – Alinta Energy, 1 February 2011 and ACIL Tasman

Table 2 shows electricity investments in coal fired power stations in the NEM over the last decade. It should be noted that investment decisions were made 3-4 years prior to the plant commissioning. Each of these investments face substantial impairment as a consequence of GHG emissions pricing and the investment would have been unlikely to have been made had GHG emissions pricing been government policy at the time.

Table 2 **Some recent coal fired investments**

Commissioned	Transaction	Estimated cost/MW
Nov 07	750 MW Kogan Creek power station	$1.60 million
Jul 03	450 MW Tarong North power station	$1.65 million
2002	850 MW Millmerran power station	$1.76 million
Jul 01	840 MW Callide C power station	$1.85 million

Data source: Various media reports and releases

While it is argued in some quarters that the industry collectively had its head in the sand with respect to GHG emissions pricing, such an argument is difficult to sustain in light of the evidence associated with transactions and investments up to the announcement in June 2007. These investments involved sophisticated investors from both the government and private sectors. In a number of cases they also involved project financing with sophisticated investor banking syndicates. It is highly unlikely that the threat of GHG emissions pricing was missed in every case.

Wholesale and retail price impacts

The advent of GHG emissions pricing will lead to increases in the wholesale electricity price and consequently retail electricity prices compared with the no further policy action case. This price rise plays a role in GHG emissions reduction. The price elasticity of demand means that demand for electricity and associated GHG emissions will fall as consumers use less electricity in response to the higher prices, either by reducing overall energy use or substituting other lower GHG emissions intense forms of energy.

Wholesale price effects

ACIL Tasman projections based on the now obsolete Carbon Pollution Reduction Scheme indicate that wholesale electricity prices will increase by around $30/MWh in nominal terms by 2020. Indicative comparative price projections (with and without GHG emissions pricing) for New South Wales, Queensland and Victoria are shown in Figure 3. The projections remain valid for GHG emissions prices similar to those projected for the CPRS-5 case. This represents a percentage cost pass through[5] of around 70% in the middle part of the decade and falling to around 60% by 2020.

Steeper trajectories such as 15% or 25% below 2000 levels by 2020 would require higher GHG emissions prices and lead to larger increases in wholesale electricity prices compared with the no further policy action case.

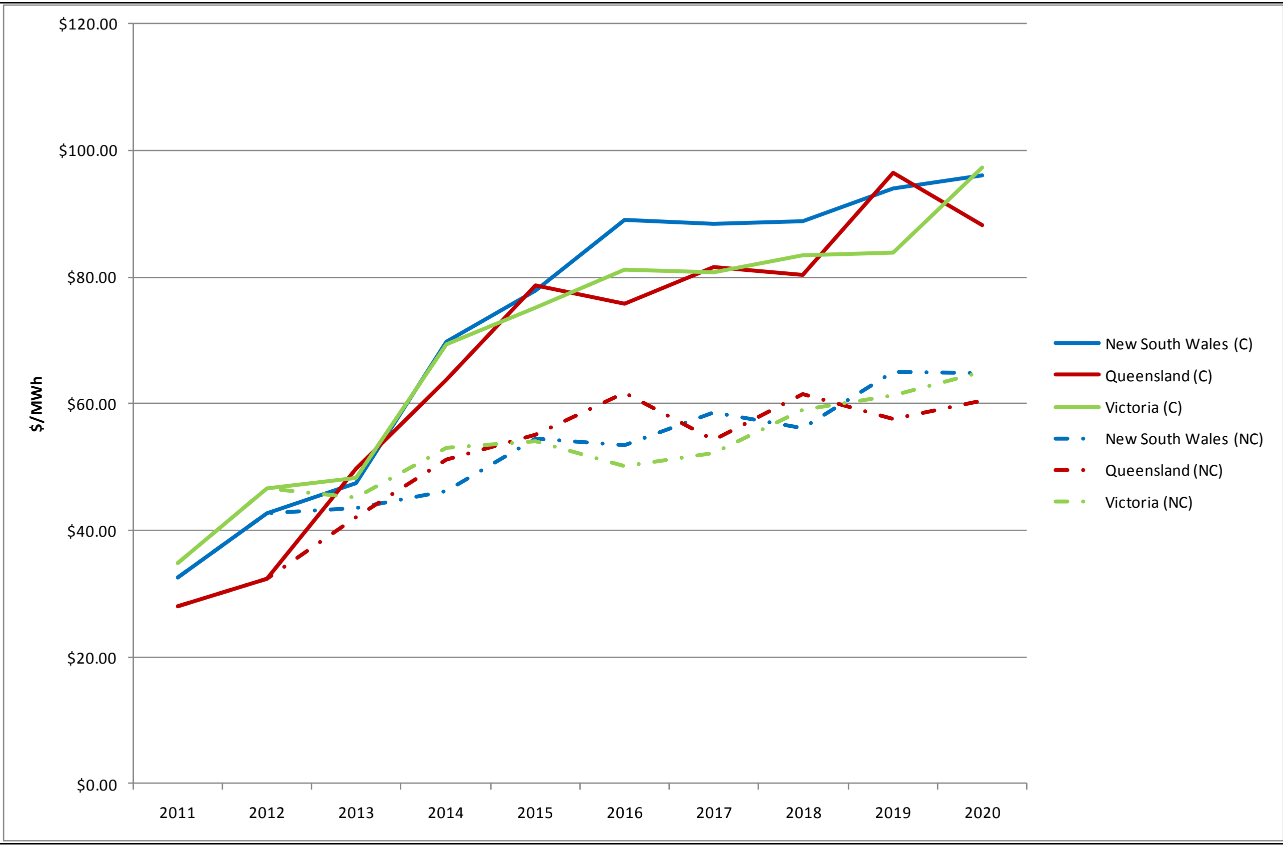
One notable issue that is worth considering is the view that ongoing uncertainty with respect to GHG emissions pricing will in itself lead to higher electricity prices. In particular it has been argued that participants are investing in lower cost OCGT rather than higher cost CCGT to

5 Pass through is calculated as the difference in the whole sale electricity price for the carbon case and no carbon case all divided by the GHG emissions price that year and then represented as a percentage.

minimise capital cost outlay but that the higher operating cost and overall cost of OCGT will push up prices.

It is noted that most OCGT that are under development are aimed at peaking cycles (OCGT are more economic for peaking) of which in part the need appears to be caused by the uncertainty of wind power investments that are being made under the Government's expanded renewable energy target. The intermittent nature of wind means that capacity is required to back up most of the installed wind capacity and OCGT are the most economic form of backup plant to provide this capability.

Figure 3 **Regional electricity price projections with and without GHG emissions pricing (2011 – 2020)**



Source: ACIL Tasman electricity market projections

Retail price effects

Wholesale electricity prices make up one component of retail electricity prices. Retail prices also include other costs such as network charges and customer service charges. The wholesale energy component of retail prices tend to follow underlying movements in wholesale prices except that movements tend to be magnified for load shaping effects.

Typically large industrial users with relatively high load factors pay only a small premium above expected wholesale prices for the energy component. On the other hand domestic consumers can pay premiums of 60%-80% depending on the distribution of wholesale prices and the shape of the load demanded.

However, GHG emissions pricing is likely to have a greater effect on off-peak prices than peak prices. This is because prices in peaks tend to be set by plants with low or zero GHG emissions intensities and often prices are set based on the value of capacity rather than the marginal cost of peaking plant. However in off-peak periods prices tend to be set by high GHG emissions intensity plant and tend to follow marginal costs more closely.

ACIL Tasman projections indicate that off-peak prices will rise by as much as twice the rise in peak prices. This means that while large industrial users will continue to pay less per MWh consumed than small users, the rise in prices for large industrial users will be greater than that for small users.

Where electricity is a significant component of input costs for large industrial users and they compete in international markets, the introduction of GHG emissions pricing will increase their cost base significantly and potentially erode their competitive and comparative advantage. This has been recognised by the current government and the need to assist trade exposed industries has been identified.